CANADA

National Energy Board

Reasons for Decision

Canterra Energy Ltd., Norcen Energy Resources Limited, Poco Petroleums Ltd., Shell Canada Limited, Vector Energy Inc., and Western Gas Marketing Limited

GH-8-88

June 1989

Gas Exports

National Energy Board

Reasons for Decision

In the Matter of

Canterra Energy Ltd., Norcen Energy Resources Limited, Poco Petroleums Ltd., Vector Energy Inc., and Western Gas Marketing Limited

Applications Pursuant to Part VI of the National Energy Board Act for Licences to Export Natural Gas

and
In the Matter of

Shell Canada Limited

Application Pursuant to Section 21 of the National Energy Board Act for a Change, Alteration or Variation of Natural Gas Export Licence GL-100

GH-8-88

June 1989

Cat. No. NE 22-1/1989-6E
ISBN 0-662-17122-5

This report is published separately in both official languages.

Ce rapport est publié séparément dans les deux langues officielles.

Copies are available on request from:

Regulatory Support Office
National Energy Board
473 Albert Street
Ottawa, Canada
K1A 0E5
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Exemplaires disponibles auprès du:

Bureau du soutien de la réglementation
Office national de l'énergie
473, rue Albert
Ottawa (Canada)
K1A 0E5
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Printed in Canada

Imprimé au Canada

Recital and Appearances

IN THE MATTER OF the *National Energy Board Act* R.S.C. 1985, c. N-7 (the Act) and the Regulations made thereunder; and

IN THE MATTER OF applications made by Canterra Energy Ltd., Norcen Energy Resources Limited, Poco Petroleums Ltd., Shell Canada Limited, Vector Energy Inc., and Western Gas Marketing Limited concerning the exportation of natural gas.

HEARD at Calgary, Alberta on 24 and 25 January 1989.

BEFORE:

J.-G. Fredette	Presiding Member
J.R. Jenkins	Member
K.W. Vollman	Member

APPEARANCES:

F.M. Saville, Q.C.	Canterra Energy Ltd.
D. Davies	Norcen Energy Resources Limited
P. McIntyre R. B. Brander	Poco Petroleums Ltd.
E.S. Decter	Shell Canada Limited
J. Rooke	Vector Energy Inc.
M.P. Stauft	Western Gas Marketing Limited
A.A. Fradsham	Alberta and Southern Gas Co. Limited
L. Keough	Boundary Gas, Inc. and Alberta Northeast Gas, Limited
A.M. Bigué	Champlain Pipeline Company
J.H. Farrell	The Consumers' Gas Company Ltd.
F.X. Berkemeier	Consumers Power Company
B. Pierce	Foothills Pipe Lines (Yukon) Ltd.
L. Keough	Midland Cogeneration Venture Limited Partnership
K.L. Meyer	Pan-Alberta Gas Ltd.
K.J. MacDonald	ProGas Limited
N.D.D. Patterson	TransCanada PipeLines Limited
R.S. Valdis	Union Gas Limited
S.S. McAllister	Alberta Petroleum Marketing Commission
J. Robitaille	Procureur général du Québec
J.A. Vockeroth	National Energy Board

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Chapter 1

The Applications

By applications dated 13, 14, 16 and 15 September 1988 Canterra Energy Ltd. (Canterra), Norcen Energy Resources Limited (Norcen), Poco Petroleums Ltd. (Poco) and Western Gas Marketing Limited (WGML) (as agent for TransCanada PipeLines Limited (TransCanada/TCPL)) respectively, requested National Energy Board approval, pursuant to Section 82 (now Section 117) of the National Energy Board Act (the Act), of licences to export natural gas to Consumers Power Company (CPCo) and Midland Cogeneration Venture Limited Partnership (MCV). By application dated 14 September 1988, Shell Canada Limited (Shell) also applied, pursuant to Section 17 (now Section 21) of the Act, for an amendment to gas export Licence GL-100 to provide for sales to CPCo and MCV.

The terms and conditions of the new or amended licences applied for by the above-mentioned applicants are listed in Table 1-1 below.

Table 1-1

Applied-for Terms and Conditions

Applicant	Licence(s)/ Amendment	Term	Exit Point	Maximum Quantities Daily	Annual	Term
Canterra	One Licence for CPCo and MCV	16 yrs. starting 1 Nov. 1988	Emer.	844 10^3m^3 (30 MMcf)	308 10^6m^3 (11 Bcf)	4 320 10^6m^3 (153 Bcf)
Norcen	Two Licences					
	- CPCo	13 yrs. starting 1 Nov. 1988	Emer.	394 10^3m^3 (14 MMcf)	144 10^6m^3 (5 Bcf)	1 830 10^6m^3 (65 Bcf)
	- MCV	11.5 yrs. starting 1 May 1990	Emer.	282 10^3m^3 (10 MMcf)	103 10^6m^3 (4 Bcf)	1 020 10^6m^3 (37 Bcf)
Poco	One Licence for CPCo and MCV	16 yrs. starting 1 Nov. 1988	Emer.	1 416 10^3m^3 (50 MMcf)	517 10^6m^3 (18 Bcf)	6 617 10^6m^3 (234 Bcf)
Shell	Amend GL-100 to include CPCo & MCV	Extend term 5 yrs. to end 1 Nov. 2004	Add Emer.	+930 10^3m^3* (33 MMcf)	+340 10^6m^3* (12 Bcf)	+3 300 10^6m^3 (117 Bcf)
WGML	Two Licences					
	- CPCo	15 yrs. starting on 1st delivery	Emer.	425 10^3m^3 (15 MMcf)	156 10^6m^3 (5 Bcf)	2 328 10^6m^3 (83 Bcf)
	- MCV	15 yrs. starting on 1st delivery	Emer.	425 10^3m^3 (15 MMcf)	156 10^6m^3 (5 Bcf)	2 328 10^6m^3 (83 Bcf)

Notes:
Quantities taken directly from the applications
* Daily and annual volumes apply from 1 January 1990 to 31 October 2003.

In addition Canterra, Norcen and Shell requested a provision which would allow the applicants to export volumes of natural gas in excess of the applied-for maximum daily quantities. WGML also requested a term extension provision which would allow for the full recovery of the authorized term volume over an extended period following the expiry date of the applied-for licence.

By application dated 29 August 1988, Vector Energy Inc. (Vector), as agent for seven Alberta natural gas producers[1], applied to the Board for a 20-year licence to export natural gas at Niagara Falls, Ontario. The natural gas would be used to fuel a new 156 megawatt (MW) combined-cycle cogeneration plant to be constructed in Pittsfield, Massachusetts. The developer, Altresco Pittsfield Incorporated (Altresco) has sold the entire electrical output of the plant to Massachusetts Electric Company (MECO) and the steam output to General Electric. The proponents of the project expect a start-up date of 1 December 1989.

Vector applied for a licence with the following terms and conditions:

Term - 1 December 1989 to 30 November 2009 (20 years)

Point of Export -
Niagara Falls, Ontario

Maximum Daily Quantity -
1 004 thousand cubic metres (36.5 MMcf)

Maximum Annual Quantity-
380 million cubic metres (13.3 Bcf)

Maximum Term Quantity -
7.6 billion cubic metres (266 Bcf)

1 Total Petroleum Canada Ltd. (Total Petroleum), Westmin Resources Limited (Westmin), Opinac Exploration Limited (Opinac), Wainoco Oil Corporation (Wainoco), Canadian Pioneer Energy Inc. (Pioneer), Ulster Petroleums Ltd. (Ulster) and Consolidated Trans-Canada Resources Ltd. (previously Trans-Canada Resources).

Chapter 2

Reasons for Decision

In considering an application for a licence to export gas, section 118 of the Act requires the Board to have regard to all considerations that appear to it to be relevant. In particular, the Board is required to satisfy itself that the quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for reasonably foreseeable Canadian requirements, taking account of trends in discovery.

To comply with the requirements of section 118 of the Act, the Board utilizes its Market-Based Procedure. This procedure includes consideration of the following: complaints, if any, under the complaints procedure; an export impact assessment; and any other factors which the Board considers relevant to its determination of the public interest including net benefits to Canada, the applicant's gas supply as it relates to reserves and productive capacity, upstream and downstream transportation arrangements and markets.

2.1 Complaints Procedure

The complaints procedure is based on the principle that gas should not be authorized for export if Canadian gas users have not had an opportunity to buy gas for their needs on terms and conditions similar to those contained in the proposed export. Thus, the complaints procedure gives Canadian users an opportunity to object to an export proposal on these grounds.

No Canadian user filed a complaint that they could not obtain additional gas supplies on terms and conditions similar to those contained in the Canterra, Norcen, Poco, Shell, WGML and Vector applications.

2.2 Export Impact Assessment

The Export Impact Assessment (EIA) helps the Board to determine whether a proposed export is likely to cause Canadians difficulty in meeting their future energy requirements at fair market prices. An applicant is required to assess the ability of Canadian natural gas producers to meet Canadian and export requirements for gas, the impact of the proposed export on domestic natural gas prices, and the ability of Canadian consumers to adjust, if necessary, their energy consumption patterns without substantial difficulty.

The burden of proof is on the applicant to demonstrate to the Board that the proposed export will not likely lead to any major difficulty for domestic consumers in meeting their energy requirements at prevailing market prices. The EIAs presented in support of the proposed gas exports addressed the required issues.

Canterra, Norcen, Poco, Shell, and WGML concluded that the expected impact of their export projects will not significantly affect the ability of Canadian consumers to obtain long-term gas supplies. They argued that the induced exploration activity resulting from the incremental exports would lead to gas reserves additions ranging from approximately 50 percent to 65 percent of the proposed export volumes. Thus, the net impact on gas reserves is expected to be a reduction of some 8.5 to 11.0 billion cubic metres (300 to 388 Bcf) which is equivalent to 0.5 percent of Canada's remaining established gas reserves. The applicants further argued that no measurable impact on domestic gas prices should be expected.

Vector concluded that the ability of Canadian gas producers to satisfy domestic and export requirements would not be reduced as a result of its proposed gas export . The applicant was also of the view that Canadian gas prices will be established on the basis of total North American supply and demand. In this context Vector does not expect the relatively small volumes of its proposed export to affect future domestic gas prices.

The Board agrees with the overall conclusion that the incremental export volumes should have little

impact on Canadian production, consumption and prices of natural gas.

2.3 Gas Supply

In its assessment of gas supply the Board examines the adequacy of reserves and productive capacity to support the applied-for export. Productive capacity projections are generally adjusted to reflect the applicant's expected requirements for gas. The adjusted productive capacity is the estimated productive capacity at any point in time, carrying forward for future use any productive capacity resulting from an earlier excess of productive capacity over production.

Each applicant provided estimates of remaining established marketable reserves for those fields from which it intends to produce natural gas for its proposed export. The Board has analyzed each applicant's supply and prepared its own estimates of the applicant's remaining gas reserves. A comparison of these estimates is shown in Table 2-1 along with the applied-for term volumes.

The above reserve estimates in conjunction with requirement projections based on an assumed load factor of 100 percent were used in preparing the productive capacity projections which follow. Thus, the requirement estimates shown in the following figures somewhat overstate the applicants' actual supply requirements.

The data underlying the productive capacity and requirements curves shown in the following figures are contained in Appendix VI.

Table 2-1

Comparison of Estimates of Remaining Marketable Established Reserves with the Applied-for Volumes

10^6m^3 (Bcf)

	Reserves Estimates[1]		
	Applicant	**NEB**	**Applied-for Volumes**
Canterra	5 232 (185)	4 090 (144)	4 320 (153)
Norcen	3 646 (129)	3 179 (112)	2 850 (101)
Shell	16 928 (598)	10 519 (371)	10 400[2] (367)
Poco	6 617[3] (234)	4 641 (164)	6 617 (234)
WGML	675 339[4] (23,840)	486 759 (17,183)	4 656[5] (164)
Vector	8 126[6] (287)	4 005 (141)	7 600 (268)

1. As at December 31, 1987
2. Total term volume under the amended licence.
3. As at March 31, 1988
4. Total WGML supply as it has not dedicated specific pools to this licence.
5. The applied-for volumes of 4 656 10^6m^3 (164 Bcf) represents only a small portion of WGML's total requirements of 815.1 billion cubic metres (28.8 Tcf) (includes evergreening of domestic and export sales).
6. As at March 8, 1989.

Canterra

Table 2-1 shows that the Board's estimate of reserves is approximately 20 percent lower than Canterra's estimate. Differences in the interpretation of pool area and net pay primarily account for the Board's lower reserves estimate. The Board notes, however, that its estimate of reserves is only slightly lower than Canterra's applied-for requirements.

Figure 2-1 compares the Board's and the applicant's projections of productive capacity associated with the respective estimates of the applicant's reserves and applied-for volumes (including fuel and shrinkage) at 100 percent load factor.

Canterra's assessment indicates adequate productive capacity for every year. The Board's projection of productive capacity suggests that there may be insufficient supply to meet demand throughout most of the proposed licence term. This difference in outlook is primarily attributable to the difference in the assessment of initial pool capability and in part due to the difference in reserves estimates as shown in Table 2-1.

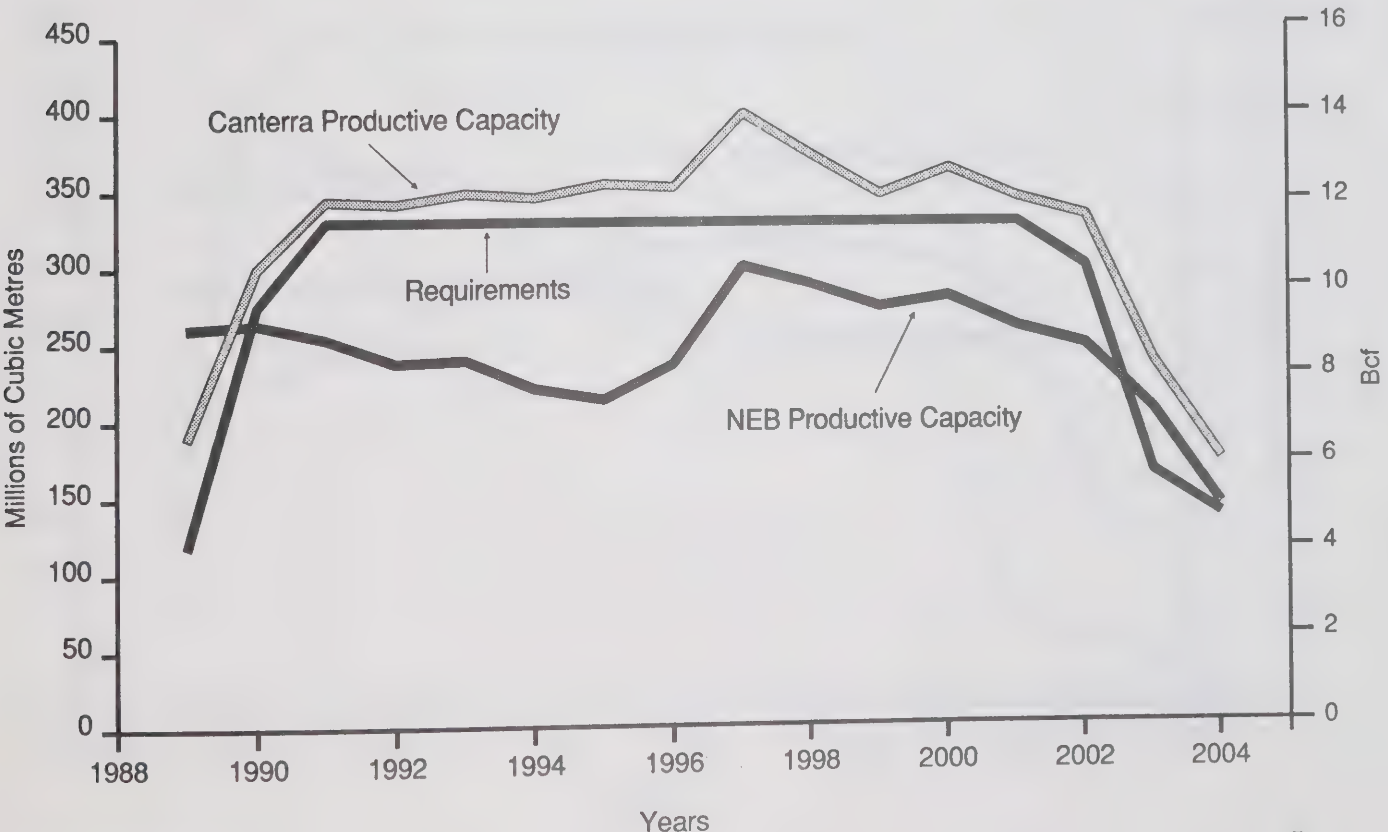
Canterra testified that, if shortfalls in productive capacity did occur, it would dedicate other properties or purchase gas from another supplier to meet its contractual obligations.

The Board notes that Canterra added additional reserves to support its Alberta removal permit application when the Alberta Energy Resources Conservation Board (ERCB) did not agree with Canterra's reserves estimates. A decision on Canterra's removal permit application is pending.

There is a minor difference between the Board's reserves estimate and the applied-for volume; further, the Board's and Canterra's productive capacity projections bracket the anticipated requirements. These factors, combined with the expectation that Canterra will take steps to address any shortfall in productive capacity, give the Board satisfaction with Canterra's overall supply situation.

Figure 2-1

Canterra Productive Capacity Comparison



Norcen

As shown in Table 2-1 the Board's estimate of Norcen's reserves is approximately 13 percent lower than the applicant's estimate. This difference in reserves estimates is mainly due to differences in the interpretation of pool area. The Board notes, however, that its estimate of reserves exceeds Norcen's applied-for requirements.

Figure 2-2 compares the Board's and the applicant's projections of productive capacity associated with the respective estimates of the applicant's reserves and applied-for volumes at a 100 percent load factor.

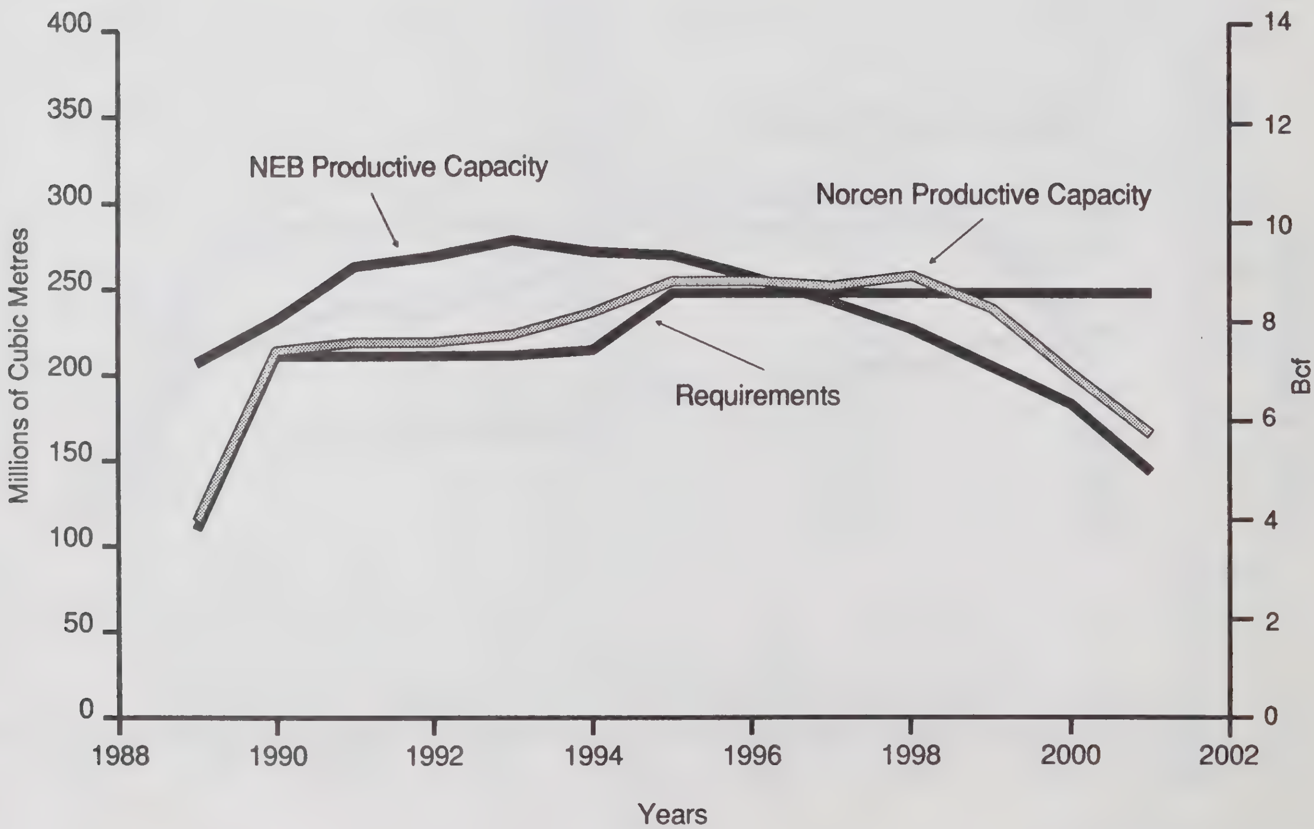
Norcen's assessment of its productive capacity indicates deficiencies in supply beginning in 1999; this compares to the Board's projection that productive capacity shortfalls may occur in 1997 and continue throughout the remainder of the proposed licence term. The applicant stated that it would optimize production from its shut-in wells and undertake development drilling on its undrilled acreage to provide additional deliverability.

The Board is of the view that the shortfalls in productive capacity, which it estimates may occur in the later stages of the proposed licence term, are sufficiently far into the future to allow for corrective action in the form of development activity. Consequently, the Board is satisfied with Norcen's supply arrangements.

The Board notes that Norcen has received Alberta removal permit GR 88-327 which allows it to remove the proposed term volume from the province.

Figure 2-2

Norcen Productive Capacity Comparison



Poco

Table 2-1 shows that the Board's estimate of Poco's dedicated established reserves is approximately 30 percent lower than Poco's estimate. Differences in the interpretation of net pay is the primary reason for the lower Board estimate.

Included in both the Board's and Poco's estimates of dedicated established reserves are reserves which Poco classified as "potential". This category consists of undrilled acreage and wells that have been drilled and tested but are not within a sufficient distance to be tied in. The Board adopted Poco's risk factor to obtain an estimate of established reserves for the "potential" category. All established reserves were discounted to reflect the proportion which Poco has dedicated to the proposed export.

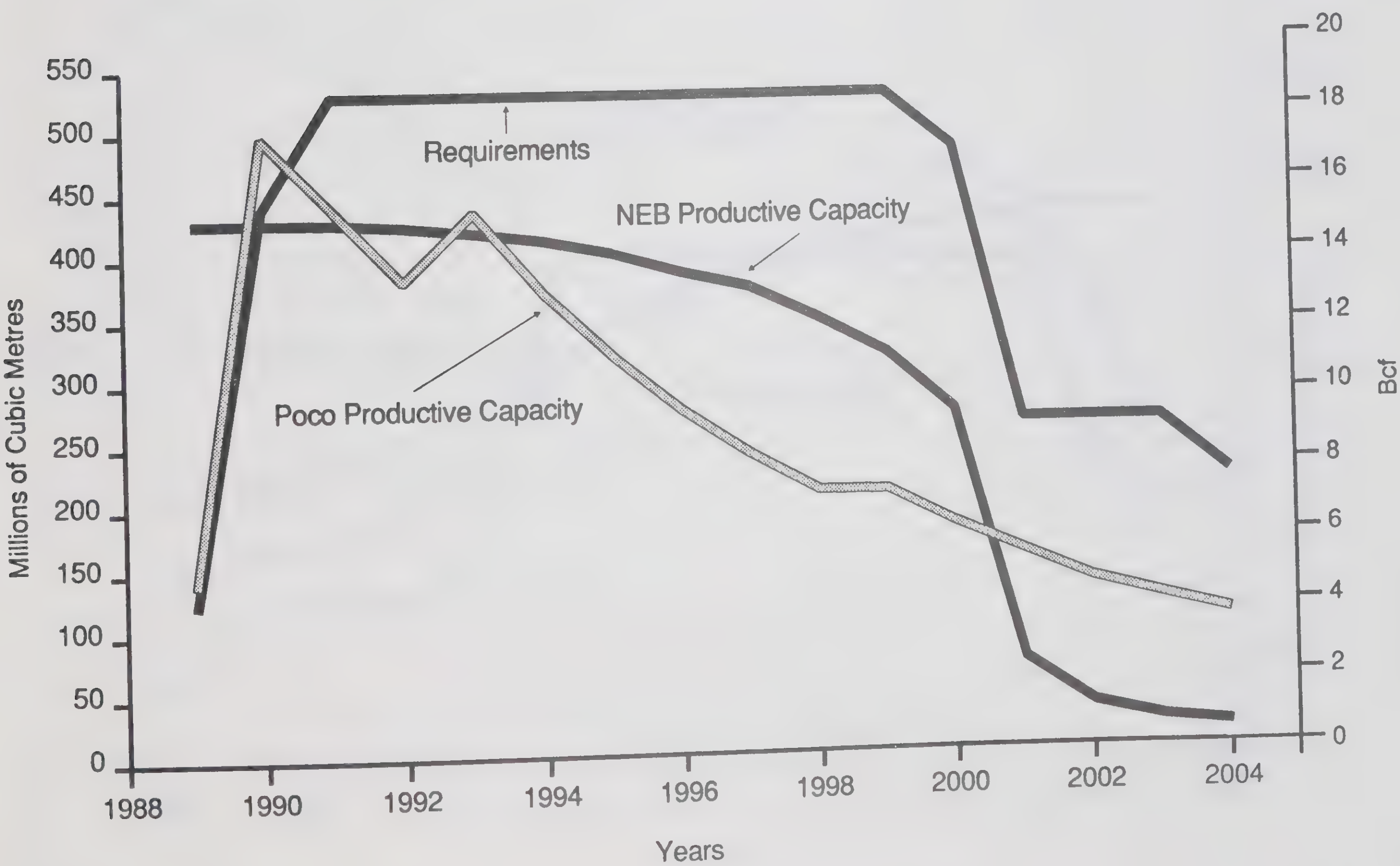
Figure 2-3 compares the Board's and the applicant's projections of productive capacity associated with the respective estimates of the applicant's reserves and the applied-for volumes (including fuel) at 100 percent load factor.

Poco's projection of productive capacity submitted to the Board indicates supply deficiencies for 14 of the 16 years of the proposed licence term. This compares to the Board's projection which suggests possible productive capacity deficiencies for 15 years. It should be noted that Poco's projection does not include productive capacity from its "potential" category. The Board has, however, modelled productive capacity from its total estimate of established reserves. Consequently, the Board's estimates of productive capacity are generally higher than Poco's estimates.

Poco stated that it could supplement its gas supply from excess volume rights, joint working interest partners or with future gas development from its potential reserves.

Figure 2-3

Poco Productive Capacity Comparison



There is a substantial difference between the NEB's estimate of Poco's reserves and the applied-for volumes. In addition, both the Board and Poco project capacity shortfalls over the majority of the licence term. Based on this evidence, the Board is not satisfied with the adequacy of Poco's supply arrangements for the full term of the proposed export.

Applications for provincial removal permits have been filed with both Alberta and Saskatchewan and decisions are pending.

Shell

Shell's estimate of reserves is approximately 40 percent higher than the Board's estimate as shown in Table 2-1. This large difference in reserves estimates is attributable to differences in the interpretation of various reservoir parameters with the main factor being pool area. The Board notes, however, that its estimate of Shell's reserves marginally exceeds the applicant's applied-for requirements.

Figure 2-4 compares the Board's and the applicant's projections of productive capacity associated with the respective estimates of the applicant's reserves.

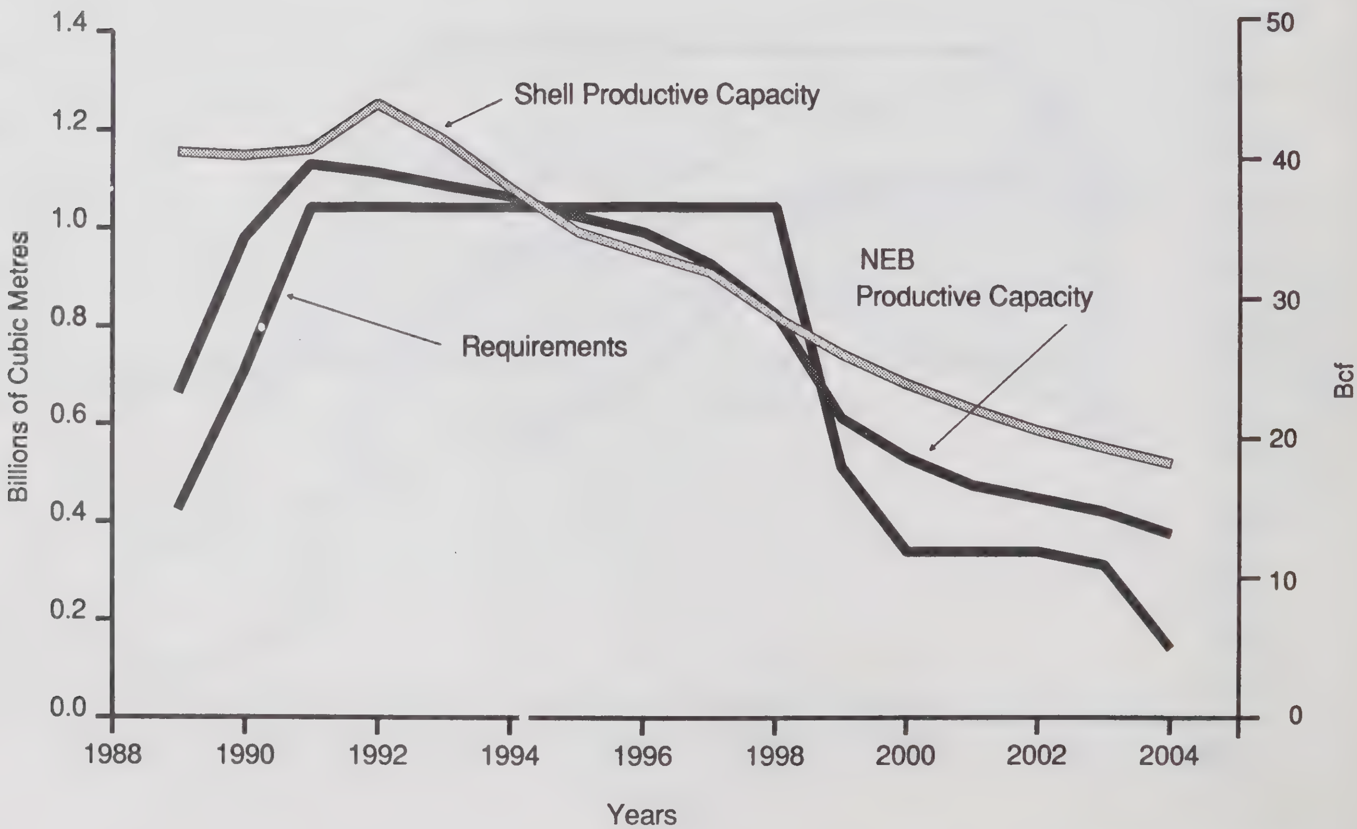
Small deficiencies in productive capacity from 1995-1999 are projected by both the Board and the applicant. Shell stated that it expects to have other sources of gas available to cover any deficiency which may occur.

The Board is satisfied with the adequacy of Shell's gas supply arrangements.

Shell currently holds Alberta removal permit GR 86-46 and has applied to the ERCB to add its share of reserves from a pool in the Clearwater field to the group of reserves already included in its removal permit. A decision is pending.

Figure 2-4

Shell Productive Capacity Comparison



WGML

WGML provided TCPL's estimates of the established reserves under contract to be used to meet existing commitments and the proposed export. Table 2-1 provides a comparison of TCPL's estimate with the Board's current estimate.

The Board's estimate of reserves is significantly lower than TCPL's estimate. Some of the reasons for this difference are different interpretation of pool performance, recovery factors and pool size. On a continuing basis, the Board is reviewing the reserves estimates of the substantial number of pools which are under contract to TCPL in order to identify and understand the reasons for the noted differences.

An assessment of TCPL's ability to satisfy its contractual commitments tends to be more complicated than that of other companies. This is largely due to the fact that the company is both the main supplier of Canadian domestic gas requirements and a major exporter.

Figure 2-5 shows TCPL's estimates of requirements and productive capacity. The projection of productive capacity is based on TCPL's estimate of reserves and requirements. The requirements projection includes evergreened domestic and export sales, as well as the applied-for volumes. TCPL's estimates indicate that productive capacity will be adequate to meet requirements until about 1995.

Figure 2-6 shows the Board's projections of TCPL's requirements and productive capacity. The projection of productive capacity is based on the Board's assessment of TCPL's reserves and requirements. The requirements estimates are the same as those used by TCPL, with the exception of export sales. Since TCPL's exports are subject to Board approval, the Board has included only authorized export levels and the export volumes sought in this application in its estimates. Corresponding

Figure 2-5

TCPL's Estimates of Requirements and Productive Capacity

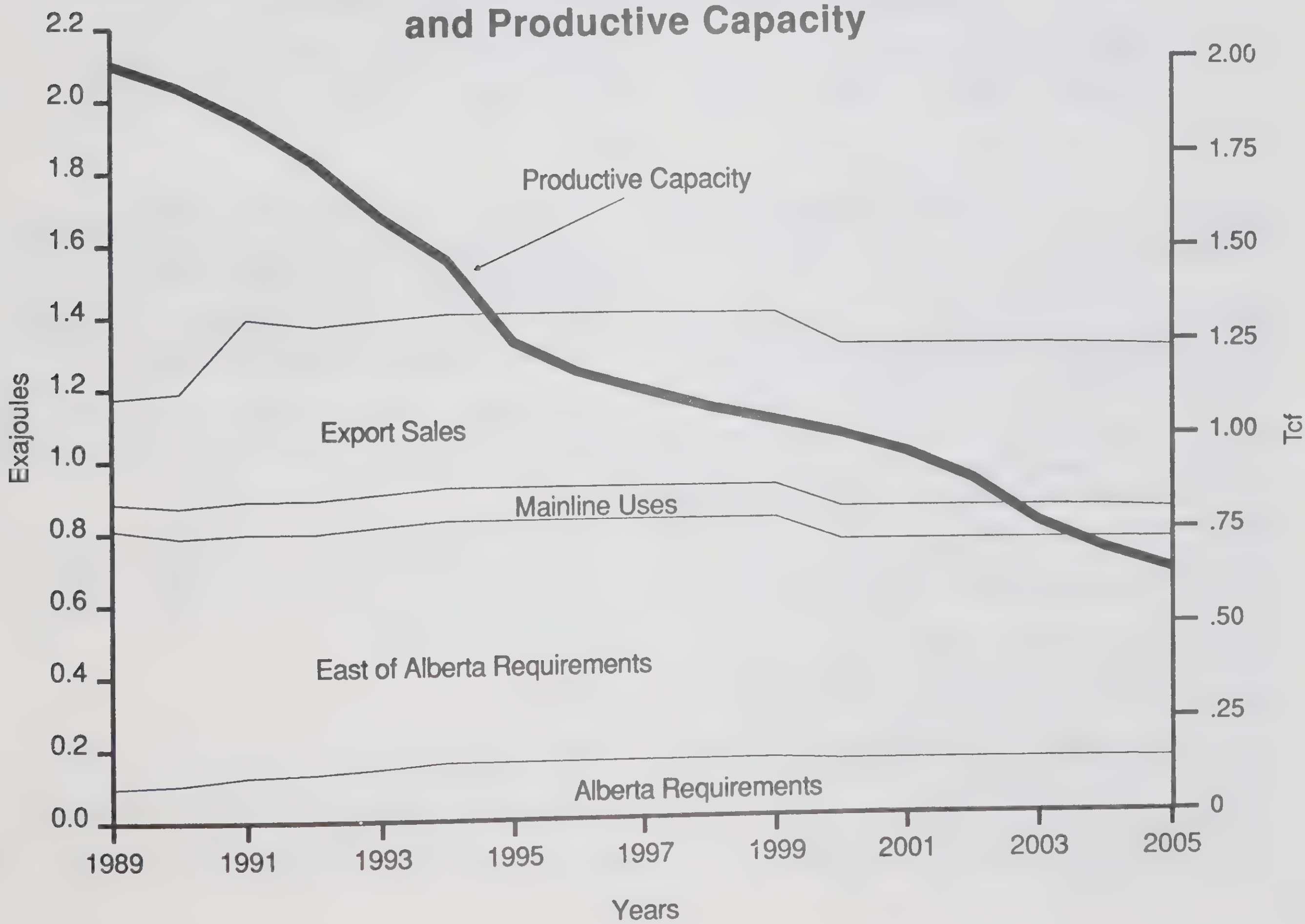
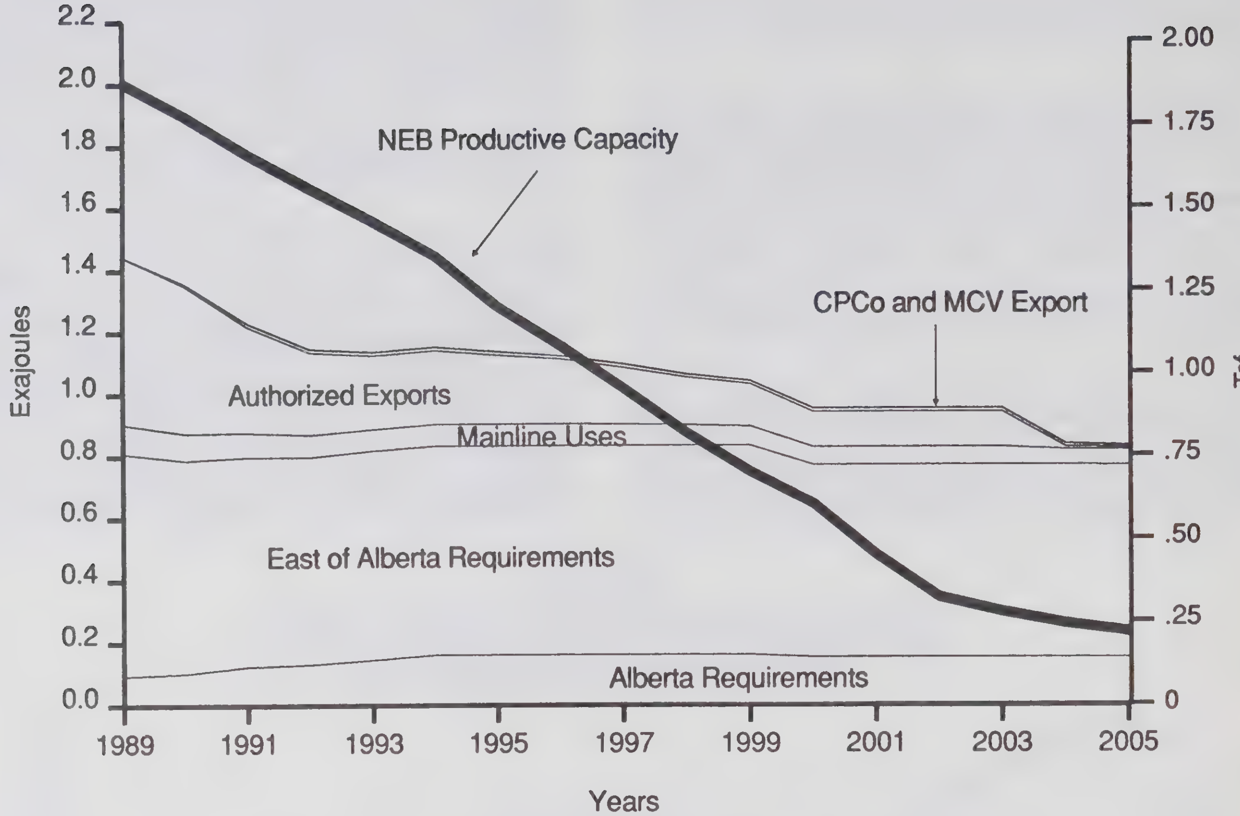


Figure 2-6

NEB Estimates of TCPL Requirements and Productive Capacity



changes were also made to the mainline uses estimates.

With regard to domestic sales, the Board notes that both the TCPL and Board estimates assume evergreening. Thus, in principle TCPL and the Board have included extensions of WGML's recently negotiated agreements with the eastern distributors. These agreements were for terms of 12 to 15 years on core markets and 3 to 5 years on direct sales. Exclusion of this evergreening assumption would substantially reduce both estimates of domestic requirements later in the period.

Figure 2-6 indicates that TCPL has sufficient productive capacity to meet its requirements until about 1997. However, the Board notes that this projection is based on the assumption that domestic sales will be evergreened. The Board is satisfied that if this assumption were not made TransCanada would have sufficient supply to meet all of its *current contractual* commitments.

The Board is also cognizant of TCPL's current inability to contract for additional reserves in light of its Topgas agreements. Anticipated higher rates of take in the future will allow TransCanada to contract for new gas supplies to improve its situation.

TCPL holds several removal permits with the majority of its reserves included in removal permit TC 85-1.

The applicant stated that it would apply to the ERCB in the near future for a minor term extension to its removal permit in order to satisfy its sales requirements.

Vector

Table 2-1 shows that the Board's estimate of reserves is less than 50 percent of Vector's estimate and substantially lower than the applied-for volumes. In determining its reserves estimate the Board did not consider Wainoco's gas pools. As

discussed in Section 2.5, it is the Board's view that there is no contractual commitment between Vector and Wainoco. The Board also did not consider pools which were added to the application after the hearing and pools for which supporting data (although requested twice) was not provided.

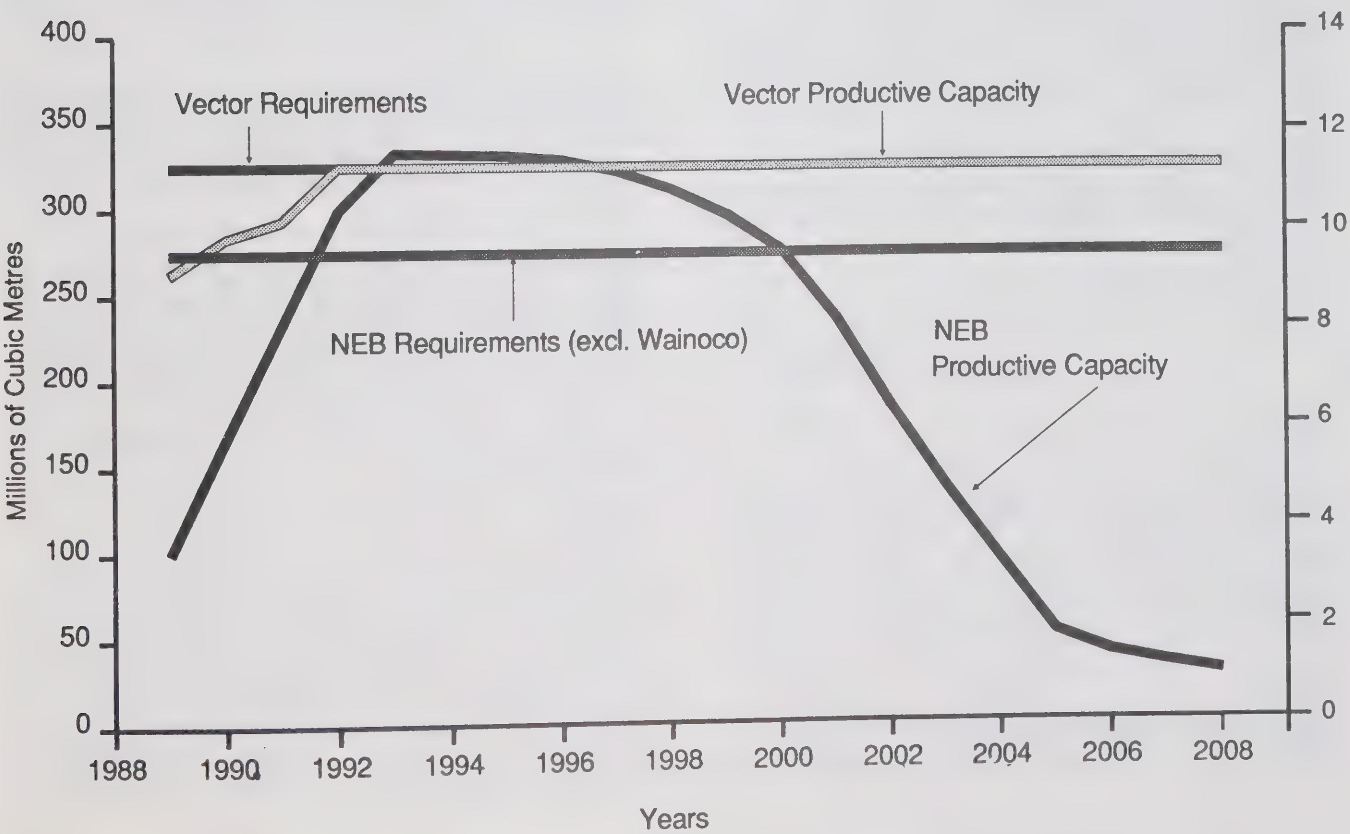
Poor gas tests and differences in the interpretation of pool area, net pay, gas saturation and recovery factor, are other reasons why the Board's reserves estimate is lower than Vector's estimate.

Figure 2-7 shows the Board's and the applicant's projections of productive capacity associated with the respective estimates of the applicant's reserves and requirements. Vector's productive capacity estimate, represented by the upper line in Figure 2-7, is based on its estimate of reserves and firm contract requirements including Wainoco, whereas the Board's estimate of productive capacity, shown in Figure 2-7, is based on the Board's estimate of Vector's reserves and a lower requirements estimate (excluding Wainoco).

Vector's assessment indicates that it has adequate productive capacity to meet its firm daily contract commitments with the exception of the initial years, on the other hand, the Board's projection of productive capacity shows deficiencies throughout much of the projection period, including the initial three years. These initial deficiencies are the result of Vector requiring several years to connect all of its reserves.

Vector indicated that it had agreed to a backstopping provision with its producer group and undertook to provide the Board with copies of its Letter Agreements with the producers. However, Vector

Figure 2-7
Vector Productive Capacity Comparison



later chose not to provide the Board with copies of its backstopping provision. The Board is of the view that no evidence has been presented which indicates that Vector has backstopping arrangements.

Considering the large deficiencies in reserves and productive capacity, the unexecuted Agency Agreement and the lack of evidence with respect to backstopping agreements, the Board is not satisfied with Vector's gas supply arrangements.

An application for an Alberta removal permit has been made to the ERCB. A decision is pending.

2.4 Markets

CPCo

The gas proposed for export to CPCo will be used as system supply for resale in CPCo's franchise area in Michigan's lower penninsula. CPCo is a combination gas and electric utility serving some 1.3 million residential, commercial and industrial customers. The CPCo market is highly seasonal and temperature sensitive. Approximately 70 percent of its sales occur in the November to April period. Despite the seasonal nature of its business, CPCo is able to maintain a high load factor on its gas purchase contracts by accessing storage capacity available from its wholly-owned subsidiary Michigan Gas Storage Company (MGSC).

Under the proposed sales agreements, Canadian gas will supply approximately ten percent of CPCo's market. The contracted maximum daily quantities are as follows:

	(10^3m^3/d)	(MMcfd)
Canterra	424.9	15.0
Norcen	396.6	14.0
Poco	708.2	25.0
Shell	424.9	15.0
WGML	424.9	15.0
Total	2 379.5	84.0

CPCo currently purchases the majority of its gas supply from Trunkline Gas Company (Trunkline) and MGSC, which in turn purchases its gas from Panhandle Eastern Pipeline Company (Panhandle). CPCo also purchases spot gas from various suppliers and gas produced in Michigan.

CPCo has undertaken a program aimed at diversifying, strengthening, and reducing the cost of its gas supply portfolio. To this end, CPCo has renegotiated its gas supply contract with Trunkline at a reduced volume. CPCo's affiliated supplier, MGSC, has also reduced its gas purchase obligations with Panhandle. As part of its efforts to diversify its gas supply, CPCo has contracted to purchase directly from the five applicants and from other U.S. producers.

CPCo noted that its purchases of Canadian gas, while diversifying its supply portfolio, will also serve to strengthen its security of supply by eliminating its historical dependence on the two aforementioned U.S. pipeline suppliers.

Although its sales have declined in recent years, CPCo does not expect that this trend will continue. Its projections indicate that the offsetting impacts of additional gas installations and conservation will result in stable gas sales over the next 15 years.

The five applicants were unanimous in their opinion that the terms and conditions of their gas sales contracts with CPCo are intended to be market responsive and encourage nominations at a high load factor.

The Board is satisfied that CPCo represents a long-term reliable export market and that the proposed export arrangements will serve in CPCo's recent efforts to diversify and strengthen its existing supply portfolio by purchasing its gas supply directly from both U.S. and Canadian gas producers.

MCV

The gas proposed to be exported to MCV will be used to fuel a gas-fired cogeneration plant being constructed at Midland, Michigan. MCV consists of several partners including CMS Energy Corp. (the parent of CPCo) and Rofan Energy Inc. (a subsidiary of the Dow Chemical Company (Dow)). The partnership was formed to acquire and convert the

unfinished, mothballed CPCo nuclear plant into a gas-fired combined-cycle cogeneration facility. Construction on the nuclear plant was halted in 1984 primarily due to cost overruns.

The plant is to consist of twelve gas-fired turbine generators, plus one steam turbine. Total generating capacity will be 1 370 MW of electricity. Some 1.35 million pounds per hour of steam will also be produced.

Construction financing for the full U.S. $600 million conversion costs has been obtained from a consortium of banks.

Conversion of the nuclear plant commenced in April 1988. Phased commercial operation is scheduled to commence in early 1990. At the time of the hearing, approximately 33 percent of the conversion funds had been spent. Several of the major facilities components had been received from the manufacturers and installed. MCV indicated that the conversion was ahead of schedule.

Most of the electrical output of the plant will be sold to CPCo under the terms of a long-term sales agreement, for resale in its franchise area in Michigan. The plant's additional electrical output and steam will be sold to the Michigan Division of Dow. The MCV facility will become the principal source of steam and electrical power for Dow.

MCV emphasized the critical need for new electric capacity in Michigan to meet the increasing demand of CPCo's electric customers.

With CPCo's commitment to purchasing 60 percent of the electrical output, Dow's commitment to purchasing up to 60 MW of electricity on an annual average basis and the prospects of electrical sales to third parties, MCV anticipates that a load factor of 70 percent will be sustainable.

MCV noted that in order to secure the necessary project financing and to complete the closing of its partnership equity arrangements, it was essential that the project have access to long-term firm gas supply and transportation commitments. To this end, MCV has contracted for 4 730 thousand cubic metres per day (167 MMcfd) of U.S. and Canadian-sourced gas, of which 2 266 thousand cubic metres per day (80 MMcfd), or some 48 percent, is Canadian. The breakdown of the Canadian-sourced gas among the five applicants is as follows:

Maximum Daily Contract Quantities

	($10^3m^3/d$)	(MMcfd)
Canterra	424.9	15.0
Norcen	283.3	10.0[1]
Poco	708.2	25.0
Shell	424.9	15.0
WGML	424.9	15.0
Total	2 266.2	80.0

1 Norcen has contracted to sell 184.1 $10^3m^3/d$ (6.5 MMcfd) until 31 October 1994 and 283.3 $10^3m^3/d$ (10.0 MMcfd) thereafter.

The MCV participants pointed out that the MCV project represents a new incremental market for Canadian gas which will not displace existing Canadian gas sales. It was also noted that the pricing provisions in the various gas sales contracts are market responsive and encourage the U.S. buyer to nominate at a high load factor.

The Board has noted the significant commitment made to the MCV Project to date by its sponsors and, in particular, the advanced stage of construction. Likewise, the Board has noted the participants' evidence that the resultant additional electric capacity of the MCV Project will be required to serve CPCo's increasing electric demand.

The Board is satisfied that the MCV Project will provide a new, high load factor, long-term market for Canadian gas.

Vector

The proposed export will be used to fuel a combined-cycle cogeneration facility currently under construction in Pittsfield, Massachusetts. The plant will have a capacity of 162 MW and is expected to cost U.S. $110 million. The facility will utilize No. 2 fuel oil as a back-up in the event of any unforeseen interruption.

The plant is a Qualifying Facility under the Public Utility Regulatory Policy Act of 1978. Rules under

this act favour industrial cogeneration and require utilities to buy power from the cogeneration plant at the utilities' avoided cost.

Massachusetts Electric Company (MECO) has contracted for all of the power output of the plant over 20 years, with an option for an additional 5 years. The contract has been approved by the Department of Public Utilities of Massachusetts. MECO is a wholly-owned subsidiary of New England Power.

The cogeneration facility is being built at General Electric's Pittsfield manufacturing and research complex. All of the steam output of the plant has been purchased by General Electric for process and heating at the Pittsfield Works.

Financing for the cogeneration facility has been arranged through General Electric Capital Corporation, which is to maintain a 20 percent equity interest in the facility.

2.5 Contracts

CPCo and MCV Sales

CPCo and MCV have each negotiated separate gas sales contracts with Canterra, Norcen, Poco, Shell and WGML for various terms of up to 15 years from the date of first firm deliveries.

While each of the contracts differ in certain respects, there are several provisions which are common. For example, each contract provides for a minimum annual quantity (MAQ) equal to 75 percent of the negotiated maximum daily quantity (MDQ) obligation during the contract year. Each contract contains certain penalty provisions in the event that the MAQ is not taken in any contract year. In most cases, this requires the buyer to make a deficiency payment at the end of each contract year equal to a specified percent of the effective commodity charge, subject to various make-up provisions.

The pricing provisions in the gas sales contracts between CPCo and MCV and each of the five Canadian suppliers are based upon a two-part demand/commodity structure charged at the Emerson, Manitoba delivery point.

With the exception of Poco, the demand charge component is equal to the sum of the monthly demand charges on the NOVA Corporation of Alberta (NOVA) and TransCanada systems. Poco's demand charge includes only the fixed costs of moving gas on the TransCanada system. Poco argued that NOVA's demand charges would be recovered through the commodity charge component.

The commodity charge component in all of the contracts is based upon a unit commodity charge calculated by subtracting the per unit monthly demand charge (based on a 100 percent load factor) from the "Reference Price".

In the case of gas exported to CPCo, the "Reference Price" is tied directly to the weighted average cost of gas paid by CPCo and MGSC for gas supply available from U.S. interstate pipelines under long-term gas supply arrangements, less the cost of transportation from the Emerson, Manitoba receipt point on the Great Lakes Gas Transmission Company (GLGT) and ANR Pipeline Company (ANR) systems (calculated at 100 percent load factor and including associated fuel costs).

The "Reference Price" in the MCV gas sales contracts consists of a base price, multiplied by an index factor intended to track CPCo's actual monthly energy charges associated with the fixed and variable expenses of operating its coal-fired electric generation plants in Michigan. This index chiefly tracks long-term U.S. coal prices, primarily eastern Kentucky low sulphur coal. Minor components of the index include short-term U.S. coal prices and general plant operating expenses.

The MCV pricing mechanism is designed to ensure that the cost of electricity from the plant compares favourably with the cost of electricity generated by the least-cost alternative.

The commencement of firm deliveries under the CPCo and MCV contracts is subject to certain conditions precedent in the gas sales contracts. The conditions precedent require, among other things, that both the buyer and seller conclude all transportation arrangements and that they secure all regulatory approvals.

Taken as a package the Board is satisfied with the terms and conditions of the various gas purchase contracts.

Vector

In support of its application Vector provided executed copies of two sales contracts. The first

contract is the purchase and sales agreement between six of the producers[1], Altresco and Vector as agent for the six producers. A separate contract, filed under covering letter dated 29 November 1988, provided the sales agreement between Wainoco and Altresco. These two contracts, with the exception of the exclusion of Vector as agent in the Wainoco/Altresco contract, are almost identical.

The gas sales contracts contain a number of conditions precedent, including the following: all Canadian and U.S. regulatory approvals; finalization of all Canadian and U.S. transportation arrangements; and approval of the Agreement by the U.S. electrical utilities purchasing the majority of the electrical output of the plant.

The term of the contracts is 20 years from the date of first deliveries. Allowance is made for the provision of interim deliveries (gas delivered in an interim period under interruptible transportation) in the initial years.

If deliveries have not commenced by 31 December 1990, or if the interim period has not ended by 31 December 1992, the agreement may be terminated by written notice by either party.

The daily quantities under the sales agreements are shown in Table 2-2.

Under the contract involving the six producers the DCQ will be supplied 30.2 percent by Westmin, 28.3 percent by Total Petroleum, 15.2 percent by Ulster, 11.3 percent by Pioneer, 7.5 percent by TransCanada Resources and 7.5 percent by Opinac. In addition, the producers shall attempt to correct any shortfalls among themselves.

The Seller may reduce the daily contract quantity by up to 20 percent at certain specified times during the term of the contract, if Altresco has not, in the preceding twenty-four month period, maintained a 75 percent load factor. Should this occur, Altresco may either agree to the reduction, or pay a specified reservation fee.

Table 2-2

Daily Contract Quantities
$10^3m^3/d$ (MMcfd)

	Six Producers, Altresco and Vector	Wainoco & Altresco
Firm	751 (26.5)	142 (5.0)
Interruptible	99 (3.5)	28 (1.0)
Total	850 (30.0)	170 (6.0)

The export price, which is set on a monthly basis, is comprised of a demand and a commodity charge component. The demand charge component is the sum of the transportation costs on the NOVA and TransCanada systems incurred by Vector for delivering the gas to the Niagara Falls, Ontario export point. The commodity charge component is set on the basis of a base price which is indexed to the price of No. 6 fuel oil, coal, and other gas supplies available to the New England market, particularly, the electric generation market. The base price is negotiable at specified annual intervals during the term of the contract. Arbitration is also provided for.

The Agreement specifies that the base price is intended to ensure a gas price which (a) is competitive with and comparable to city gate gas prices paid for long-term supplies delivered to local distribution companies located in Connecticut, Massachusetts and Rhode Island; and (b) permits the cogeneration facility to be dispatched as a base load fossil fuel electric generation plant operating at a 75 percent load factor. In the event of a dispute the contract stipulates that item (b) shall prevail.

The Agency Agreement

Vector also provided an unexecuted copy of the proposed Agency Agreement between itself and the seven producers. During the hearing the Board requested an executed copy of the Agreement be filed. In response Vector, under covering letter dated 7 March 1989, provided copies of the Agency Agreement with counterpart signature pages executed by five of the seven producers. Total Petroleum and Wainoco had not yet executed the agreement but Vector anticipated receiving the documents in the near future, upon which they would forward copies to the Board. In this regard the Board notes the Agency Agreement becomes valid and binding only upon execution by all parties.

1 See footnote on page 2 of this report (excluding Wainoco).

Although the above Agency Agreement has not been fully executed, the Board is satisfied that based on the gas sales and purchase contract that Vector is acting as agent for six of the seven producers. The Board, however, has no evidence before it to demonstrate that Vector is acting as Wainoco's agent. Wainoco executed a separate sales and purchase agreement with Altresco and it has not executed the Agency Agreement submitted by Vector.

2.6 Transportation and Related Facilities Construction

CPCo and MCV Sales

The gas proposed for export to CPCo and MCV will be transported in Alberta on the NOVA system to the point of interconnection with the facilities of TransCanada near Empress, Alberta. TransCanada will transport the gas to the international boundary near Emerson, Manitoba.

With the exception of the gas to be supplied by Poco, CPCo and MCV are to arrange for their respective transportation services downstream of Emerson, Manitoba. CPCo is to arrange for transportation service on the systems of GLGT and ANR for delivery to various points of interconnection in CPCo's franchise area. MCV is to arrange for transportation service on the GLGT, CPCo and MGSC pipeline systems for delivery of the gas to its cogeneration facility.

In the case of Poco, all transportation arrangements downstream of Emerson, Manitoba were to be contracted for by the Company. However, during the hearing, Poco testified that it was renegotiating its gas sales contracts with both CPCo and MCV to change the delivery point to Emerson, Manitoba, thereby making the purchaser responsible for all downstream transportation arrangements.

With respect to transportation services upstream of the Emerson, Manitoba delivery point, the five applicants are at various stages in their respective negotiations with NOVA and TransCanada.

With the exception of 269 thousand cubic metres per day (9.5 MMcfd) of pipeline capacity, TransCanada has received conditional authorization from the Board to construct the facilities needed to supply the CPCo and MCV sales. Authorization for the additional 269 thousand cubic metres per day (9.5 MMcfd) is being sought in TransCanada's 1990 facilities application (GH-1-89), which is currently before the Board.

Similarly, downstream of the Emerson, Manitoba export point, CPCo and MCV are continuing their efforts to finalize their respective transportation service agreements on the GLGT, ANR and MGSC pipeline systems.

To accommodate the MCV imports, GLGT will be required to install approximately 134 kilometres (83 miles) of 914 millimetre (36 inch) looping at a cost of U.S. $75.3 million. An application has been made to the Federal Energy Regulatory Commision and is awaiting decision pending the Commission's environmental assessment. In addition, MCV will be required to install a 660 millimetre (26 inch), 40 kilometres (25 mile) lateral to link the MCV facility with the CPCo/MGSC system. Construction of this lateral is expected to be completed in the fall of 1989. No new facilities are required on the GLGT system to accommodate delivery of the CPCo imports.

Vector

The gas proposed for export to Altresco will be transported in Alberta on the NOVA system to the point of interconnection with the facilities of TransCanada for transportation to Niagara Falls, Ontario. From the international border the gas would be transported by Tennessee Gas Pipeline Company (Tennessee) to a new proposed interconnection with the Berkshire Gas Company (Berkshire). All of the pipeline systems require facilities construction, including a connector line between Berkshire and the plant.

By December 1989, Vector expects to have firm transportation service on the NOVA system for 80 percent of the firm export volumes. Transportation service for the remaining 20 percent of the firm portion would be available on an interruptible basis. Vector anticipates being able to contract for firm transportation service for the total firm export volume of 892.3 $10^3m^3/d$ (31.5 MMcfd) by 1990. The remaining 141.6 $10^3m^3/d$ (5.0 MMcfd) will always be interruptible.

Vector has concluded a precedent transportation service agreement with TransCanada and is continuing its negotiations with TransCanada to finalize that interim agreement.

From the border the natural gas will be transported by Tennessee to a new interconnection with Berkshire. All of the pipeline systems require facilities expansion and applications have been made to the appropriate regulatory bodies.

Interim transportation arrangements on Tennessee, CNG Transmission Co. and Berkshire are being pursued in the event that regulatory delays occur. Berkshire, a Massachusetts LDC, has agreed to construct the necessary pipeline facilities connecting its distribution system with the Pittsfield facility.

2.7 Benefit-Cost Analysis

CPCo and MCV Sale

The five applicants submitted a joint benefit-cost analysis of their proposed exports to CPCo and MCV. Table 2-3 provides a summary of the applicants' results.

Three scenarios were explored in the applicants' benefit-cost analysis to test the sensitivity of net benefits to different price forecasts. All three cases assumed that the real prices of gas sold to MCV, which are tied to the costs of operating CPCo's coal-fired generating facilities, would remain constant over the life of the contracts. The real prices of gas sold to CPCo were also assumed to remain constant in the low case, but were assumed to increase at two percent and four percent per annum in the base and high cases respectively. In the initial year of the contracts the average border price was assumed to be \$2.28/GJ (\$2.45/MMBtu) (1988 Cdn.\$) for sales to MCV and \$2.34/GJ (\$2.51/MMbtu) (1988 Cdn.\$) for sales to CPCo.

An average load factor of 84.9 percent was assumed for the term of the contracts. Gas by-product revenues were estimated to be 20 percent of the value of the gas production associated with the exports.

The estimates of transportation costs included an allowance for approximately \$25 million of direct

Table 2-3

Applicants' Joint Benefit-Cost Analysis of the Proposed Gas Exports
(in millions of 1988 Canadian dollars at an 8 percent discount rate)

	Low Case	Base Case	High Case
BENEFITS (Revenues)			
Gas Exports	962.9	1032.1	1111.3
Sales of By-products	199.0	213.8	230.6
Total	**1161.9**	**1245.9**	**1341.9**
COSTS			
Production Costs			
Capital	136.1	136.1	136.1
Operating	216.4	216.4	216.4
Transportation Costs			
Capital	68.3	68.3	68.3
Operating	108.1	112.3	117.0
User Cost	234.9	213.7	192.5
Total	**763.8**	**746.8**	**730.3**
NET SOCIAL BENEFIT	**398.1**	**499.1**	**611.6**
BENEFIT/COST RATIO	**1.5**	**1.7**	**1.8**

The estimates of transportation costs included an allowance for approximately $25 million of direct capital expenditures on the TransCanada system and $43 million on the NOVA system in Alberta. The reason for the low estimate of facilities costs on the TransCanada system is the existence of some unused capacity on TransCanada's western section which was assigned a zero opportunity cost by the applicant.

In their calculation of user costs, the applicants employed a supply cost curve which assumed that the real full-cycle production costs of natural gas would increase slowly over the next twenty years.

The results indicated that the applied-for exports should yield net benefits to Canada of about $499 million in the base case, with a range from $398 million in the low case to $611 million in the high case, assuming an 8 percent discount rate.

In summary, the applicants argued that their proposed exports would provide significant net benefits to Canada and that it would be in the Canadian public interest to grant the applied-for licences.

No intervenors disputed the reasonableness of the submitted results and none argued that the proposed exports would not yield net economic benefits to Canada.

The Board notes that the specific contractual pricing terms vary from applicant to applicant but that the prices for the proposed sales to CPCo are based upon average natural gas acquisition costs of the U.S. pipelines that supply gas to CPCo whereas the prices for the proposed sales to MCV are based upon the average costs of operating CPCo's coal-fired generating facilities. As it is generally expected that natural gas prices will increase at a faster rate than coal prices, the proposed sales to CPCo will provide for more attractive netbacks to the producers than the proposed sales to MCV.

Although the pricing terms vary from contract to contract, the submitted benefit-cost analysis was based on the contractual terms aggregated across all the sales contracts to both CPCo and MCV for all five export licence applicants. The Board notes that the proposed sales to CPCo and MCV were presented to WGML's producers as a package deal. Further, no parties to the hearing objected to evaluating the applied-for exports on a combined basis.

The Board conducted its own benefit-cost analysis of the export licence applications on a combined basis. As shown in Table 2-4, the Board's analysis indicates that the expected net benefits are likely to vary between $89 million in the low case and negative $122 million in the high case. The low and high cases in the Board's analysis are based upon the low and high scenarios developed in Board staff's October 1988 Report, *Canadian Energy Supply and Demand 1987-2005* (the Supply and Demand Report). The low case scenario is based upon an outlook for world annual economic growth of about two percent per year, accompanied by modest increases in world oil prices and North American natural gas prices. The high case scenario is based upon an outlook for world annual economic growth of about three percent per year, accompanied by more rapid increases in world oil prices and North American natural gas prices. In addition, supply costs for Canadian natural gas were assumed to increase more rapidly in the high case than in the low case. The Board believes that these two scenarios provide a reasonable range of likely future oil and gas prices.

Discrepancies between the applicants' and the Board's estimates of gas export revenues and by-product revenues are minor and arise from small differences in exchange rate assumptions and gas price forecasts. The Board accepts the applicants' assumed average load factor of 84.9 percent as being a reasonable estimate for the base case analysis.

The Board accepts the applicants' estimates of their production costs as being a fair reflection of the likely costs to be incurred.

With respect to facilities costs, the Board is of the view that the theoretically correct measure of incremental facilities costs to be attributed to an export applicant should be:

1) the net present value of expected facilities cost expenditures including the applied-for export; minus

2) the net present value of the expected facilities cost expenditures excluding the applied-for export.

To estimate capital costs in this manner would require a forecast of annual facilities cost expenditures with and without the applied-for export

Table 2-4

Board's Benefit-Cost Analysis of the Proposed Gas Exports
(millions of 1988 Canadian dollars at an 8 percent discount rate)

	Low Case	High Case
BENEFITS (Revenues)		
Gas Exports	996	1138
Sales of By-products	178	295
TOTAL	**1174**	**1433**
COSTS		
Production Costs	302	302
Transportation Costs		
Operating	19	19
Capital	72	72
User Costs	691	1161
TOTAL	**1085**	**1555**
NET SOCIAL BENEFIT	**89**	**(122)**
BENEFIT/COST RATIO	**1.08**	**0.92**

licence. However, the Board considers that the marginal cost of expansion on the western section of the TransCanada system is roughly constant over the forecast period. Furthermore, throughput on TransCanada's western section is likely to rise over the forecast period. Consequently, the incremental capital expenditures on TransCanada's western section attributable to an applied-for licence would be approximately equal to the costs of advancement in time of the direct capital expenditures associated with the capacity expansion.

The Board notes that this methodology is only applicable if there is a reasonable expectation that throughputs on the relevant sections will increase over time. If it were not reasonable to expect that throughputs would increase, then the full direct incremental facilities costs as spent at the time of construction should be allocated to an export applicant. The Board expects that, in the circumstances of this application, it is reasonable to expect that the facilities will be required beyond the applied-for licence term.

The Board also notes that any expenditures on new facilities which cannot be reasonably expected to be utilized by other shippers should also be fully attributed to the export applicant. This could apply, for example, to any dedicated spurs or laterals that might serve specific markets.

The major difference between the applicants' analysis and the Board's analysis is in the estimates of user cost. The applicants' analysis assumes, in all three of its cases, that supply costs will increase at a slower rate than that assumed in the Board's low case scenario. The Board is of the view that future supply costs of natural gas are likely to increase within the bounds outlined in its 1988 Supply and Demand Report and, hence, the applicants' estimated user costs understate the real user costs likely to be incurred.

Table 2-5 shows the results of sensitivity analyses of the Board's results to different discount rates, higher and lower gas and coal prices, a lower load factor and, for the purpose of the user cost calculation, different export demand forecasts. Net benefits are estimated to be positive in the low case and negative in the high case because the higher gas price forecast in the high case results in an uneven effect on gas export revenues and user costs.

Table 2-5

Sensitivity Analyses of the CPCo and MCV Export Licence Applications
(Net Benefits in millions of 1988 Canadian dollars)

	Low Oil Price Scenario	High Oil Price Scenario
BASE CASE	89	(122)
Different Discount Rates		
6% Discount Rate	52	(233)
10% Discount Rate	64	(75)
Different U.S. Gas Prices		
10% Higher	135	(62)
10% Lower	42	(183)
Different U.S. Coal Prices		
10% Higher	133	(78)
10% Lower	45	(166)
Load Factor Sensitivities		
75% Load Factor	90	(86)
User Cost Sensitivities		
Exports at 1.2 EJ/yr	146	(36)
Exports at 1.8 EJ/yr	57	(164)

Higher gas prices in the high case yield higher export revenues, but the effect is muted because the proposed sales to MCV, which represent roughly half of the applied-for export volumes, are tied to coal prices. Higher gas prices are also associated with higher future supply costs and, therefore, user costs are much higher in the high case than in the low case. The effect on user costs is not muted, however, because higher supply costs are associated with all the export volumes.

In summary, the Board finds that any benefits to Canada from the proposed exports will most likely be attributable to the gas exports to CPCo. Export sales to MCV are unlikely, on their own, to provide net benefits to Canada because export prices tied to coal prices will probably not rise as quickly as the replacement cost of gas. The Board accepts that the proposed exports, taken together, are reasonably likely to recover the associated costs in Canada including a normal return on investment.

Vector

Table 2-6 shows the summary results of the benefit-cost analysis which Vector submitted in support of its application. The study indicates that the applied-for exports should yield net benefits to Canada ranging between approximately $28 million (1988$) and $117 million (1988$) in the applicant's high and low cases respectively, assuming all project benefits and costs are discounted at an 8 percent discount rate.

The applicant's low and high world oil price scenarios are distinguished only by different assumptions about future natural gas supply costs. Future supply costs are assumed to increase more rapidly in the high case scenario than in the low case scenario, resulting in higher estimated user costs in the high case scenario. As shown in Table 2-6, all other cost and revenue projections are identical in the low and high cases.

Table 2-6

Vector's Benefit-Cost Analysis of its Export Proposal
(millions of 1988 Canadian dollars
at an 8 percent discount rate)

	Low Case	High Case
BENEFITS		
Gas Exports	277	277
Sales of By-products	87	87
TOTAL	**364**	**364**
COSTS		
Production Costs	45	45
Transportation Costs	79	79
User Costs	123	212
TOTAL	**247**	**336**
NET SOCIAL BENEFIT	**117**	**28**
BENEFIT-COST RATIO	**1.47**	**1.08**

The export price is tied to a fossil fuel index which represents the average cost to New England electrical utilities of purchasing coal, heavy fuel oil and U.S. natural gas for the purpose of electricity generation. Fifty percent of the index is based on the price of number 6 residual fuel oil with a 2.2 percent sulphur content, as landed at New York City Harbour. The applicant assumed a 1989 fuel oil price of U.S. $17.00/barrel with an average annual real increase of about 2.5 percent over the life of the contract.

Twenty-five percent of the index is based on New England Power Company's weighted average delivered cost of thermal coal. Coal prices were forecast to average U.S. $1.57/MMBtu ($1.46/GJ) in 1989 and to escalate thereafter by 1 percent per year in real terms. The final twenty-five percent of the index is based on Tennessee Pipeline Company's weighted average cost of gas (WACOG). Tennessee's WACOG was assumed to average U.S. $2.20/MMBtu ($2.05/GJ) in 1988 and forecast to increase at 2 percent per year in real terms over the life of the contract. The above assumptions with respect to price, along with a forecast average load factor of 75 percent in each year of the contract, formed the basis for the applicant's forecast of export revenues.

The applicant estimated by-product revenue per unit of marketable gas delivered to NOVA to be 12 percent of the world oil price on a heat equivalent basis.

Under the terms of the gas sales contracts, Altresco pays the producers for fuel gas provided to TransCanada and NOVA. Hence, these revenues were deemed to be a benefit equivalent to revenues from gas exports. Revenues for fuel gas supplied to TransCanada and NOVA were estimated on the basis of a 12 percent and 0.5 percent fuel ratio respectively.

The applicant's submission indicated that it had all the necessary reserves to support its sales over the contract term and that, because most of the capital expenditures had already been incurred, field development costs would average only $0.37 GJ ($0.40/MMBtu).

Estimated transportation costs included $73 million of capital expenditures on TransCanada, as

per the estimate provided to Vector by TransCanada. The applicant estimated that about $8.4 million in capital expenditures on the NOVA system could be attributed to its export licence application, assuming additional costs on NOVA could be allocated to all incremental volumes on a pro-rata basis. In addition, the estimated transportation costs included an allowance for real incremental operating costs associated with transporting the forecast export volumes.

The applicant estimated the user costs to be associated with the forecast export volumes using the supply cost estimates and domestic natural gas demand forecasts outlined in the low and high case scenarios of Board staff's September 1988 report, *Canadian Energy, Supply and Demand 1987-2005.* In order to estimate user costs attributable to an incremental export, it is necessary to prepare a forecast of total gas production in absence of the applied-for export. In selecting its forecast, Vector chose to use the lesser of licensed export volumes or a February 1988 IPAC export forecast. Because licensed export volumes in effect at the time of Vector's application drop off sharply after 1994, the applicant's methodology results in an export demand forecast in which exports drop below 8.5 10^9m^3/year (300 Bcf/year) after 1994 and decline thereafter.

The applicant maintained that its methodology was appropriate because it focussed the analysis on the user cost of export authorizations over and above currently-licensed levels.

In summary, Vector argued that its exports would provide net benefits to Canada. No intervenors disputed the reasonableness of the submitted results and none argued that the proposed exports would not yield net economic benefits to Canada.

The Board finds that, on balance, the applicant's forecast of export prices, revenues and by-product revenues is reasonable. The Board notes that, to be consistent with the low and high cases presented by the applicant with respect to user cost, separate forecasts of revenues could have been provided for the applicant's low and high cases.

It is the Board's understanding that the estimates of fuel gas revenues as shown in Table 2-6 are overstated because they were mistakenly based on a marginal fuel ratio of 12 percent on TransCanada's system, rather than on the average fuel ratio, which is estimated at 7.75 percent.

The Board does not agree with the estimates of production costs submitted in the benefit-cost analysis. As discussed in Section 2.3, it appears that the applicant does not have sufficient reserves to support production of either the applied-for or the forecast export volumes. Further, on the basis of the information submitted by Vector, a significant amount of development work remains to be done on Vector's established reserves in order to achieve deliverability capability. In the Board's view, Vector's production costs for its demonstrated established reserves would be at least equal to industry averages of about $0.72/GJ ($0.77/MMBtu).

The Board recognizes that Vector submitted its estimate of the associated incremental facilities costs on TransCanada's system according to information supplied to Vector by TransCanada. This estimate was based on the direct incremental facilities costs associated with Vector's application based on the facilities costs in TransCanada's 1989-90 facilities application (GH-4-88).

The Board, however, is of the view that the theoretically correct measure of incremental facilities costs to be attributed to an export applicant should be:

1) the net present value of expected facilities cost expenditures including the applied-for export; minus

2) the net present value of expected facilities cost expenditures excluding the applied-for export.

To estimate capital costs in this manner would require a forecast of annual facilities cost expenditures with and without the applied-for export licence. However, the Board considers that the marginal cost of expansion on the relevant sections of the TransCanada system is roughly constant over the forecast period. Furthermore, throughputs on TransCanada's western and central sections are likely to rise over the forecast period. Consequently, the incremental capital expenditures on TransCanada's western and central sections attributable to an applied-for licence would be approximately equal to the costs of advancement in time of the direct capital expenditures associated with the capacity expansion.

The Board notes that this methodology is only applicable if there is a reasonable expectation that

throughputs on the relevant sections will increase over time. If there are grounds for such an expectation, it is reasonable to assume that other shippers would use the available capacity if the applied-for licence were not renewed upon termination of its term. If it were not reasonable to expect that throughputs would increase, then the full direct incremental facilities costs as spent at the time of construction should be allocated to an export applicant.

The Board also notes that any expenditures on new facilities which cannot be reasonably expected to be utilized by other shippers should also be fully attributed to the export applicant. This could apply, for example, to any dedicated spurs or laterals that might serve specific markets.

The Board does not agree with the methodology used by the applicant in calculating user costs. The applicant's forecast of export demand in the absence of its proposed exports appears to severely understate the exports that are likely to flow during the forecast period. Indeed, the applicant's forecast implies that pipeline facilities would be under-utilized as existing licences expire and that alternative export market opportunities for Canadian natural gas would not exist.

A further undesirable aspect of using licensed exports for the demand forecast would be the potential unequal treatment of export applicants; i.e. two licence applicants with the same volumes and contractual pricing arrangements would be evaluated differently if it so happened that the level of licensed exports were different at the time each application was submitted.

User cost arises because increased production from existing reservoirs accelerates the timeframe in which higher cost reservoirs must be exploited. Thus, user cost is a function of the gas production profile over time, and bears no direct relation to the level of licensed exports. In the Board's view, the correct approach is to use a reasonable projection of export demand in the absence of the applied-for export and, as with other components of the analysis, to conduct tests of the sensitivity of the user cost estimates to lower or higher levels of future exports.

The Board prepared its own benefit-cost analysis of Vector's export application. As discussed in Section 2.3, the Board is of the view that Vector does not have sufficient established reserves to produce the applied-for volumes over the full length of the applied-for licence term. The Board has also excluded consideration of Wainoco's volumes in its assessment of the application. Accordingly, the Board undertook its benefit-cost analysis on the basis of export volumes of 850 10^3m^3/day (30.0 MMcf/day) over a 15 year licence term, as opposed to the applied-for 1034 10^3m^3/day (36.5 MMcf/day) over a 20 year licence term.

The Board conducted its analysis under a low and high oil price scenario, each of which is consistent with the price and cost projections contained in the low and high oil price scenarios in the Board's 1988 Supply and Demand Report.

The Board estimated the incremental facilities costs associated with the Vector application on the TransCanada and NOVA systems according to the methodology described above. The Board believes that in this case it is reasonable to assume that throughputs will continue to rise on the affected pipeline segments and, hence, this methodology is applicable.

The total incremental production costs attributable to a new export consists of direct production costs, adjusted for a credit for by-product revenues, and user costs. In estimating the total incremental production costs of the export, the Board forecast both domestic and export demand according to the projections in the low and high cases of its 1988 Supply and Demand report. The export volumes which the Board considered for licensing were then deducted from these projections to determine the production profile in the absence of the export. The total incremental production costs attributable to these volumes were then calculated as:

(1) the net present value of the total production costs of all projected production with the export; minus

(2) the net present value of the total production costs of all projected production without the export.

Subtracting the applicant's own direct production costs from the remainder of (1) minus (2) yields the estimated user costs attributable to the applied-for export. These direct production costs were assumed to be \$0.72/GJ (\$0.77/MMBtu), equal to the approximate industry average. If direct produc-

tion costs were higher, user costs would be decreased by an offsetting amount. Thus, as long as production of an applicant's gas reserves would not constitute a serious distortion from the optimal path of producing all incremental reserves, an exact estimate of the applicant's direct production costs is not critical to the analysis.

The Board's methodology yielded somewhat higher user costs than estimated by the applicant.

The results of the Board's base case benefit-cost analysis in the low and high oil price scenarios are shown in Table 2-7. The Board's analysis indicates that the exports are unlikely to recover the associated costs incurred in Canada. The primary reason for this result is the relatively unattractive pricing terms in the export sales contract.

Table 2-8 shows the results of sensitivity analyses of the Board's results to different discount rates, higher and lower world oil prices and U.S. gas prices, different load factors and, for the purposes of the user cost calculation, different export demand forecasts.

The sensitivity tests of the net benefits at a 6 percent discount rate indicate lower net benefits than in the base case at an 8 percent discount rate in both the low and high oil price scenarios. The use

Table 2-7

Board's Benefit-Cost Analysis of Vector's Export Licence Application[1]
(millions of 1988 Canadian dollars at an 8 percent discount rate)

	Low Oil Price Scenario	High Oil Price Scenario
BENEFITS		
Gas Export Revenue	175	215
By-Product Revenue	32	53
Fuel Gas Revenue	8	11
TOTAL	**215**	**279**
COSTS		
Production Costs	53	53
Marketing Costs	2	2
Transportation Costs		
- Operating	3	3
- Capital	41	41
User Costs	128	213
TOTAL	**227**	**313**
NET SOCIAL BENEFITS	**(13)**	**(34)**
BENEFIT/COST RATIO	**0.94**	**0.89**

1. This table is not directly comparable to Table 2-5 because the applicant based its analysis on the applied-for volumes of 1004 10^3m^3/day (36.5 MMcf/day) over a 20 year licence term whereas the Board's analysis is based on 850 10^3m^3/day (30.0 MMcf/day) at a 75 percent load factor over a 15 year licence term. User costs are calculated on the basis of projected growth in total domestic natural gas demand, plus projected growth in export demand rising to 1.5 EJ (1.4 Tcf) by 1994. Totals may not add exactly due to rounding.

Table 2-8

Sensitivity Analyses of Vector's Export Licence Application
(Net Benefits in millions of 1988 Canadian dollars)

	Low Oil Price Scenario	High Oil Price Scenario
BASE CASE*	**(13)**	**(34)**
Different Discount Rates		
6% Discount Rate	(15)	(48)
10% Discount Rate	(20)	(31)
Different World Oil Prices		
10% Higher	(7)	(24)
10% Lower	(18)	(44)
Different U.S. Gas Prices		
10% Higher	(10)	(31)
10% Lower	(15)	(37)
Load Factor Sensitivities		
60% Load Factor	(3)	(20)
90% Load Factor	(21)	(47)
User Cost Sensitivities		
Exports at 1.2 EJ/yr	(4)	(18)
Exports at 1.8 EJ/yr	(18)	(42)

*Note: The base case reflects all of benefit-cost assumptions shown in Table 2-7.

of a lower discount rate in a viability analysis is normally expected to yield higher net present benefits because the present value of the future revenue stream increases more than the present value of the capital and production costs as the discount rate decreases. However, because user costs are incurred over time, the use of a lower discount rate also results in a higher net present value of these costs. In this analysis, the increase in the net present value of the user costs outweighs the increase in the net present value of the revenue stream when a 6 percent discount rate is employed.

The Board also notes that the net benefits decline slightly as the assumed load factor increases from both 60 percent to 75 percent and from 75 percent to 90 percent. This occurs because the marginal revenue from incremental sales does not recover the combined marginal production and user costs as the production level increases.

The results of the sensitivity analyses indicate that, under a broad range of plausible assumptions about key variables in the analysis, the exports do not provide net benefits to Canada.

Chapter 3

Disposition

3.1 Canterra, Norcen, Poco, Shell and WGML

The Board has decided to issue new and separate licences to each of the five applicants involved in the sales to CPCo and MCV. Although Canterra and Poco each requested a single licence and Shell requested an amendment to Licence GL-100 to include the proposed sales to CPCo and MCV, the Board has decided for reasons of consistency and administrative efficiency to issue two new licences to each applicant. In addition, the Board has requested Governor in Council approval of an amendment to Licence GL-100 to reflect the reduced requirements of Granite State as outlined in Shell's application. Appendices I to V contain the terms and conditions of the proposed licences and amending order, including the requirement that exports under the new licences must commence on or before 31 December 1991. Should this condition not be met, the licences shall terminate.

The Board notes that to implement the decision, Governor in Council approval of the new licences and the amending order is required.

In arriving at its decision the Board considered all matters relevant, including whether the volumes to be exported are surplus to reasonably foreseeable Canadian requirements. In this regard, the Board noted the absence of any complaints or opposition to the proposed exports. In addition, the applicants filed a joint EIA study which demonstrated that the proposed exports would have little or no impact on total production, gas prices and consumption patterns. Based on the evidence, the Board is satisfied that the proposed exports are surplus to reasonably foreseeable Canadian requirements.

The Board also assessed a number of other public interest items, including gas supply, markets, gas sales contracts, transportation arrangements and a benefit-cost analysis of the proposed exports.

The Board reviewed each applicant's gas supply and productive capacity and has compared it with its own estimates. In all cases with the exception of Poco the Board was satisfied with the adequacy of the gas supply arrangements. In Poco's case the Board was not convinced that Poco has sufficient dedicated reserves to supply the project over the entire term. Consequently, the Board has decided to issue a licence to Poco for its sales to MCV with a term of 12 years and for a term volume of 2 715 million cubic metres (95.8 Bcf). This compares with Poco's request for a single licence which incorporated an MCV term of 16 years and a term volume of 3 749 million cubic metres (132.3 Bcf).

The Board also reviewed the applicants' evidence on markets and contracts and believes that the proposed exports to CPCo and MCV will occur at fairly high load factors.

The applicants submitted a benefit-cost analysis based on the contractual terms for the aggregate of the proposed sales to both CPCo and MCV. The Board accepts that, on a combined basis, the exports are reasonably likely to recover associated costs in Canada including a normal return on investment. However, the Board is of the view that the proposed sales to MCV would not provide net benefits to Canada if analyzed on a stand-alone basis. Although the Board accepts that, in the context of these applications, it is reasonable to do an economic assessment on a combined basis, the Board is only prepared to issue licences with respect to the sales to MCV on the explicit condition that such sales be linked to the sales to CPCo. Accordingly, the Board has included a condition in each of the MCV licences which requires that annual volumes exported under these licences not exceed the actual volumes exported under each applicant's corresponding CPCo licence.

The Board denies Canterra's, Norcen's and Shell's requests for authorization of volumes in excess of the maximum daily quantity. Although the Board is not opposed to license flexibility, it was not

convinced by the evidence that the commercial arrangements require such flexibility, and even if required, how such a mechanism would work. The Board does not accept Shell's proposed mechanism of increasing the daily, annual and term quantities of the licence by ten percent.

The Board also denies WGML's request for an extended licence term to allow for the recovery of underdeliveries. The proposed term of the licences being issued to WGML mirrors that of the commercial arrangements that WGML has negotiated with the buyers. In the event of underdeliveries, WGML can then amend its commercial arrangements and apply to the Board for an extension of the term.

In addition the Board has decided to reduce, where appropriate, the applied-for daily, annual and term quantities to coincide with the commercial arrangements between the applicants and the buyers. In the case of Norcen's MCV licence this results in lower licenced volumes in the initial years to 31 October 1994.

3.2 Vector

In assessing the evidence the Board considered all matters relevant, including whether the volumes to be exported are surplus to reasonable foreseeable Canadian requirements. In this regard the Board noted the absence of any complaints and the results of the applicant's EIA. Based on the evidence the Board is satisfied that the proposed export is surplus to reasonable foreseeable Canadian requirements.

The Board is not satisfied with the contractual relationships underpinning the project. In assessing an export application, the Board considers it important that the major parties involved in the project have executed their contractual commitments to one another as evidence of commercial substance to the proposal. Of primary importance are the contractual relationships between the producers, the buyer, the seller and the marketer of the gas.

Although the Board would have preferred to have seen an executed Agency Agreement between Vector and the six producers, it is satisfied that based on the Vector/Altresco/six Producers sales contract that Vector is representing these producers. However, the Board is not satisfied that Vector is acting as Wainoco's agent, as evidenced by Wainoco's failure to execute the Agency Agreement and by the separate sales contract between Wainoco and Altresco.

The Board is also not satisfied with Vector's overall gas supply. The Board's estimates of Vector's gas supply and productive capacity are substantially lower than those of the applicant. The Board's estimates did not include Wainoco's reserves since there was no contractual evidence that Vector represents Wainoco. The Board's estimates also excluded various reserves for which Vector did not provide gas reserve data sheets. This applies as well to those additional reserves which Vector incorporated as part of its response to an undertaking to the Board on deliverability.

The Board also assessed Vector's benefit-cost analysis and has prepared its own estimates. The Board's analysis indicates that, in the base case and under a wide range of sensitivities, the export would not recover the associated costs in Canada. The primary reason for this result is the relatively unattractive pricing terms in the gas sales contract.

The Board is not satisfied that the proposed export is in the public interest: the Board has major concerns regarding Vector's evidence on gas supply and contracts; and the Board's benefit-cost analysis indicates that the applied-for export is unlikely to recover the costs in Canada. Therefore, the Board denies Vector's application for an export licence.

J.-G. Fredette
Presiding Member

J.R. Jenkins
Member

K.W. Vollman
Member

Terms and Conditions of the Licences to be Issued to Canterra

Terms and Conditions of the Licence for Exports to CPCo

1. The term of this Licence shall commence on the date of Governor in Council approval hereof and end on 31 October 1991, unless exports commence hereunder on or before 31 October 1991, in which case the term will end on 31 October 2003.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 424 900 cubic metres in any one day;

   (b) 155 100 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 2 099 100 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that Canterra may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that Canterra may export under the authority of this Licence in any calendar month may exceed the quantity allowable during that period by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Emerson, Manitoba.

Terms and Conditions of the Licence for Exports to MCV

1. The term of this Licence shall commence on the date of Governor in Council approval hereof and end on 31 December 1991, unless exports commence hereunder on or before 31 December 1991, in which case the the term will end on 31 October 2004.

2. (a) Subject to subcondition (b) and condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (i) 424 900 cubic metres in any one day;

   (ii) 155 100 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (iii)2 246 400 000 cubic metres during the term of this Licence.

   (b) During the period that Licence No. GL-(A) is in effect, the quantity of gas that may be exported under the authority of this Licence, during any consecutive twelve-month period ending on 31 October, shall not exceed the actual quantity of gas exported to Consumers Power Company during that same period under the authority of Licence No. GL-(A).

3. (a) As a tolerance, the amount that Canterra may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that Canterra may export under the authority of this Licence in any calendar month may exceed the quantity allowable during that period by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Emerson, Manitoba.

(A) Would refer to the licence issued with respect to exports to CPCo.

Terms and Conditions of the Licences to be Issued to Norcen

Terms and Conditions of the Licence for Exports to CPCo

1. The term of this Licence shall commence on the date of Governor in Council approval hereof and end on 31 October 1991, unless exports commence hereunder on or before 31 October 1991, in which case the term will end on 31 October 2001.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 396 600 cubic metres in any one day;

   (b) 144 500 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 1 841 000 000 cubic metres during the term of this Licence.

3. As a tolerance, the amount that Norcen may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Emerson, Manitoba.

Terms and Conditions of the Licence for Exports to MCV

1. The term of this Licence shall commence on the date of Governor in Council approval hereof and end on 31 December 1991, unless exports commence hereunder on or before 31 December 1991, in which case the term will end on 31 October 2001.

2. (a) Subject to subcondition (b) and condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (i) for the period commencing on the date of Governor in Council approval hereof, and ending on 31 October 1994, 184 100 cubic metres in any one day, or 67 200 000 cubic metres during any consecutive twelve-month period ending on 31 October;

   (ii) for the period commencing on 1 November 1994, and ending on 31 October 2001, 283 300 cubic metres in any one day, or 104 800 000 cubic metres during any consecutive twelve-month period ending on 31 October; or

   (iii) 1 034 000 000 cubic metres during the term of this Licence.

   (b) During the period that Licence No. GL-(A) is in effect, the quantity of gas that may be exported under the authority of this Licence, during any consecutive twelve-month period ending on 31 October, shall not exceed the actual quantity of gas exported to Consumers Power Company during that same period under the authority of Licence No. GL-(A).

3. As a tolerance, the amount that Norcen may export in any 24-hour period under the authority of this Licence may exceed the daily limitations imposed in condition 2 by ten percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Emerson, Manitoba.

(A) Would refer to the licence issued with respect to exports to CPCo.

Terms and Conditions of the Licences to be Issued to Poco

Terms and Conditions of the Licence for Exports to CPCo

1. The term of this Licence shall commence on the date of Governor in Council approval hereof and end on 31 October 1991, unless exports commence hereunder on or before 31 October 1991, in which case the term will end on 31 October 2000.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 708 200 cubic metres in any one day;

   (b) 258 500 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 2 843 500 000 cubic metres during the term of this Licence.

3 (a) As a tolerance, the amount that Poco may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that Poco may export under the authority of this Licence in any calendar month may exceed the quantity allowable during that period by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Emerson, Manitoba.

Terms and Conditions of the Licence for Exports to MCV

1. The term of this Licence shall commence on the date of Governor in Council approval hereof and end on 31 December 1991, unless exports commence hereunder on or before 31 December 1991, in which case the term will end on 31 October 2000.

2. (a) Subject to subcondition (b) and condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (i) 708 200 cubic metres in any one day;

   (ii) 258 500 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (iii) 2 715 300 000 cubic metres during the term of this Licence.

   (b) During the period that Licence No. GL-(A) is in effect, the quantity of gas that may be exported under the authority of this Licence, during any consecutive twelve-month period ending on 31 October, shall not exceed the actual quantity of gas exported to Consumers Power Company during that same period under the authority of Licence No. GL-(A).

3. (a) As a tolerance, the amount that Poco may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that Poco may export under the authority of this Licence in any calendar month may exceed the quantity allowable during that period by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Emerson, Manitoba.

(A) Would refer to the licence issued with respect to exports to CPCo.

Appendix IV

Terms and Conditions of the Licences and Licence Amendment to be Issued to Shell

Terms and Conditions of the Licence for Exports to CPCo

1. The term of this Licence shall commence on the date of Governor in Council approval hereof and end on 31 October 1991, unless exports commence hereunder on or before 31 October 1991, in which case the term will end on 31 October 2003.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

    (a) 424 900 cubic metres in any one day;

    (b) 155 100 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

    (c) 2 234 000 000 cubic metres during the term of this Licence.

3. As a tolerance, the amount that Shell may export under the authority of this Licence may, in any 24-hour period, exceed the daily limitation imposed in condition 2 by ten percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Emerson, Manitoba.

Terms and Conditions of the Licence for Exports to MCV

1. The term of this Licence shall commence on the date of Governor in Council approval hereof and end on 31 December 1991, unless exports commence hereunder on or before 31 December 1991, in which case the term will end on 31 October 2004.

2. (a) Subject to subcondition (b) and condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

    (i) 424 900 cubic metres in any one day;

    (ii) 155 100 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

    (iii) 2 250 000 000 cubic metres during the term of this Licence.

    (b) During the period that Licence No. GL-(A) is in effect, the quantity of gas that may be exported under the authority of this Licence, during any consecutive twelve-month period ending on 31 October, shall not exceed the actual quantity of gas exported to Consumers Power Company during that same period under the authority of Licence No. GL-(A).

3. As a tolerance, the amount that Shell may export under the authority of this Licence may, in any 24-hour period, exceed the daily limitation imposed in condition 2 by ten percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Emerson, Manitoba.

Amended Terms and Conditions of Shell's Export Licence No. GL-100

Condition 2 of Shell's export Licence No. GL-100 will be amended so as to reduce the authorized

(A) Would refer to the licence issued with respect to exports to CPCo.

term quantity from 7 100 000 000 to 5 900 000 000 cubic metres. Specifically, condition 2 will be revoked and substituted therefor will be the following:

"2. (1) The quantity of gas that may be exported under the authority of this Licence shall not exceed for the period commencing on 1 November 1987 and ending on 31 March 1999:

(a) at Niagara Falls, Ontario, 1 390 000 cubic metres in any one day, or 400 000 000 cubic metres in any consecutive twelve-month period ending on 31 October;

(b) at Highwater, Quebec, 1 110 000 cubic metres in any one day, or 300 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

(c) 5 900 000 000 cubic metres during the term of this Licence.

(2) Notwithstanding the annual quantities that may be exported under paragraphs 2(1)(a) and 2(1)(b), the Licensee may, for the period commencing on 1 November 1987, and ending on 31 October 1998, export a quantity of gas during any consecutive twelve-month period ending on 31 October which quantity when added to the cumulative quantity exported to date, will not exceed the sum of the annual quantities authorized to that date."

Terms and Conditions of the Licences to be Issued to WGML

Terms and Conditions of the Licence for Exports to CPCo

1. The term of this Licence shall commence on the date of Governor in Council approval hereof and end on 31 October 1991, unless exports commence hereunder on or before 31 October 1991, in which case the term will end on 31 October 2003.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 424 900 cubic metres in any one day;

   (b) 155 100 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

(c) 2 326 500 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that WGML/TransCanada may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that WGML/TransCanada may export in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Emerson, Manitoba.

Terms and Conditions of the Licence for Exports to MCV

1. The term of this Licence shall commence on the date of Governor in Council approval hereof and end on 31 December 1991, unless exports commence hereunder on or before 31 December 1991, in which case the term will end on 31 October 2004.

2. (a) Subject to subcondition (b) and condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

      (i) 424 900 cubic metres in any one day;

      (ii) 155 100 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

      (iii) 2 326 500 000 cubic metres during the term of this Licence.

   (b) During the period that Licence No. GL-(A) is in effect, the quantity of gas that may be exported under the authority of this Licence, during any consecutive twelve-month period ending on 31 October, shall not exceed the actual quantity of gas exported to Consumers Power Company during that same period under the authority of Licence No. GL-(A).

3. (a) As a tolerance, the amount that WGML/TransCanada may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that WGML/TransCanada may export in any twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Emerson, Manitoba.

(A) Would refer to the licence issued with respect to exports to CPCo.

Table A-1
Comparison of Productive Capacity Forecasts
(millions of cubic metres)

Year	Estimated Total Demand	NEB Adjusted Productive Capacity	NEB Spare Capacity	Canterra Adjusted Productive Capacity	Canterra Spare Capacity
	(1)	(2)	(3)	(4)	(5)
1989	118	261	143	189	71
1990	275	264	-11	300	25
1991	330	254	-76	344	14
1992	330	238	-92	342	12
1993	330	240	-90	349	19
1994	330	221	-109	346	16
1995	330	214	-116	355	25
1996	330	237	-93	353	23
1997	330	301	-29	401	71
1998	330	289	-41	374	44
1999	330	274	-56	348	18
2000	330	281	-49	365	35
2001	330	261	-69	346	16
2002	301	249	-52	334	33
2003	165	206	41	238	73
2004	137	143	6	173	36

Notes:
Col. (1) = 100 percent load factor + fuel and shrinkage
Col. (2) = Adjusted Productive Capacity using NEB's estimates of reserves
Col. (3) = Col (2) - Col. (1)
Col. (4) = Productive Capacity projection submitted by Canterra
Col. (5) = Col. (4) - Col. (1)

Table A-2

Comparison of Productive Capacity Forecasts
(millions of cubic metres)

		NEB		Norcen	
Year	Estimated Total Demand	Adjusted Productive Capacity	Spare Capacity	Adjusted Productive Capacity	Spare Capacity
	(1)	(2)	(3)	(4)	(5)
1989	110	207	97	115	5
1990	211	232	21	214	3
1991	211	263	52	219	8
1992	211	269	58	219	8
1993	211	278	67	223	12
1994	214	271	57	236	22
1995	247	269	22	254	7
1996	247	256	9	254	7
1997	247	242	-5	251	4
1998	247	226	-21	257	10
1999	247	204	-43	238	-9
2000	247	182	-65	200	-47
2001	247	143	-104	165	-82

Notes:
Col. (1) = 100 percent load factor + fuel and shrinkage
Col. (2) = Adjusted Productive Capacity using NEB reserves
Col. (3) = Col (2) - Col. (1)
Col. (4) = Productive Capacity projection submitted by Norcen
Col. (5) = Col. (4) - Col. (1)

Table A-3

Comparison of Productive Capacity Forecasts
(millions of cubic metres)

Year	Estimated Total Demand	NEB Adjusted Productive Capacity	NEB Spare Capacity	Poco Adjusted Productive Capacity	Poco Spare Capacity
	(1)	(2)	(3)	(4)	(5)
1989	123	429	306	140	17
1990	440	429	-11	497	-57
1991	528	428	-100	440	-88
1992	528	425	-103	381	-147
1993	528	420	-109	436	-92
1994	528	413	-115	371	-158
1995	528	402	-126	320	-209
1996	528	387	-142	276	-252
1997	528	374	-154	240	-289
1998	528	348	-180	209	-319
1999	528	319	-209	209	-319
2000	484	272	-212	181	-303
2001	264	71	-193	158	-107
2002	264	34	-230	134	-130
2003	264	22	-242	120	-144
2004	220	16	-204	107	-113

Notes:
Col. (1) = 100 percent load factor + fuel and shrinkage
Col. (2) = Adjusted Productive Capacity using NEB reserves
Col. (3) = Col (2) - Col. (1)
Col. (4) = Productive Capacity projection submitted by Poco
Col. (5) = Col. (4) - Col. (1)

Table A-4

Comparison of Productive Capacity Forecasts
(millions of cubic metres)

Year	Estimated Total Demand	NEB Adjusted Productive Capacity	NEB Spare Capacity	Shell Adjusted Productive Capacity	Shell Spare Capacity
	(1)	(2)	(3)	`(4)	(5)
1989	426	665	239	1155	729
1990	709	980	271	1147	438
1991	1041	1129	88	1159	118
1992	1042	1112	70	1252	210
1993	1041	1085	44	1177	136
1994	1041	1062	21	1080	39
1995	1041	1022	-19	991	-50
1996	1042	990	-52	948	-94
1997	1041	926	-115	908	-133
1998	1041	823	-218	818	-223
1999	511	611	100	742	231
2000	338	529	191	680	342
2001	338	473	135	629	291
2002	338	446	108	585	247
2003	310	419	109	550	240
2004	142	374	232	518	376

Notes:
Col(1) = 100 percent load factor + fuel and shrinkage
Col. (2) = Adjusted Productive Capacity using NEB reserves
Col. (3) = Col (2) - Col. (1)
Col. (4) = Productive Capacity projection submitted by Shell
Col. (5) = Col. (4) - Col. (1)

Table A-5

WGML's Estimates of Requirements and Productive Capacity
(Petajoules)

Year	Estimated Total Demand	TCPL Adjusted Productive Capacity	TCPL Spare Capacity
	(1)	(2)	(3)
1988	1076	2108	1032
1989	1175	2100	925
1990	1191	2036	845
1991	1395	1944	549
1992	1375	1830	455
1993	1393	1678	285
1994	1409	1557	148
1995	1410	1330	-80
1996	1410	1244	-166
1997	1410	1193	-217
1998	1407	1142	-265
1999	1407	1104	-303
2000	1316	1065	-251
2001	1316	1012	-304
2002	1316	936	-380
2003	1316	815	-501
2004	1315	738	-577
2005	1308	680	-628
2006	1308	628	-680
2007	1308	576	-732
2008	1308	532	-776
2009	1308	456	-852
2010	1308	420	-888

Notes:
Col. (1) = WGML's estimated total demand.
Col. (2) = Productive Capacity projection submitted by WGML
Col. (3) = Col. (2) - Col. (1)

Table A-6

NEB Estimates of WGML's Requirements And Productive Capacity

(Petajoules)

Year	Estimated Total Demand	NEB Adjusted Productive Capacity	NEB Spare Capacity
	(1)	(2)	(3)
1988	1287	2093	806
1989	1445	2005	560
1990	1351	1897	546
1991	1230	1773	543
1992	1146	1662	516
1993	1136	1555	419
1994	1152	1443	291
1995	1152	1280	128
1996	1149	1153	4
1997	1133	1016	-117
1998	1100	873	-227
1999	1080	748	-332
2000	990	645	-345
2001	990	482	-508
2002	990	345	-645
2003	990	298	-692
2004	838	261	-577
2005	837	235	-602
2006	825	191	-634
2007	825	170	-655
2008	825	147	-678
2009	825	127	-698
2010	825	104	-722

Notes:
Col. (1) = WGML's estimated Domestic Demand plus currently authorized exports.
Col. (2) = Adjusted Productive Capacity using NEB reserves
Col. (3) = Col (2) - Col. (1)

Table A-7

Comparison of Productive Capacity Forecasts
(millions of cubic metres)

Year	Estimated Total Demand	NEB Adjusted Productive Capacity	NEB Spare Capacity	Vector Adjusted Productive Capacity	Vector Spare Capacity
	(1)	(2)	(3)	(4)	(5)
1989	274	101	-173	262	-12
1990	274	168	-106	283	9
1991	274	233	-41	294	20
1992	274	299	25	325	51
1993	274	333	59	325	51
1994	274	332	58	325	51
1995	274	331	57	325	51
1996	274	329	55	325	51
1997	274	322	48	325	51
1998	274	311	37	325	51
1999	274	296	22	325	51
2000	274	275	1	325	51
2001	274	235	-39	325	51
2002	274	183	-91	325	51
2003	274	137	-137	325	51
2004	274	94	-180	325	51
2005	274	52	-222	325	51
2006	274	39	-235	325	51
2007	274	33	-241	325	51
2008	274	28	-246	325	51

Notes:
Col. (1) = Vector's Firm requirements at a 100 percent load factor (excl. Wainoco)
Col. (2) = Adjusted Productive Capacity using NEB reserves
Col. (3) = Col (2) - Col. (1)
Col. (4) = Productive Capacity projection submitted by Vector
Col. (5) = Col. (4) - Col. (1)